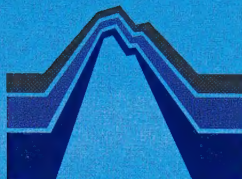


1999

annual report

AR71



Paramount
resources ltd.

Winepear Business Reference Library
University of Alberta
1-18 Business Building
Edmonton, Alberta T6G 2R6

*the wolf has good claim to the title of
most adaptable, and therefore most successful,
predator on earth*



man excepted

returning

shareholder value

***what we've been doing
for the past 21 years
successfully***

***managing the parts of
the equation within our
control, and endeavouring
to influence those beyond
it – in short –***

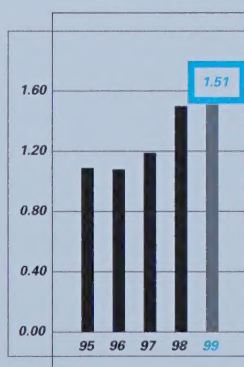
adapting

corporate profile

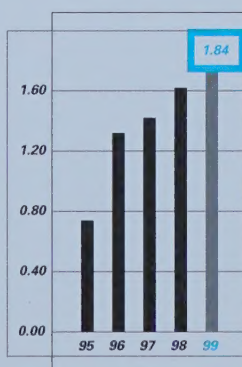
Paramount Resources Ltd. is a Canadian energy company with 92 percent of its revenue derived from natural gas sales. The Company explores for, develops, processes, transports and markets petroleum and natural gas. Since its inception in 1978, the Company has concentrated on the full cycle exploration and development of high deliverability shallow gas in northeastern Alberta. In the early to mid-90s, through successful exploration, Paramount diversified from this traditional area of focus, adding new core areas in Central and Northwest Alberta. Over the last three years, Paramount has spearheaded the resurgence of exploration north of the 60th parallel in the Northwest Territories. Throughout its history, Paramount has successfully adapted to a myriad of operating climates to record sustainable growth per share in production, cash flow, earnings, and asset value.

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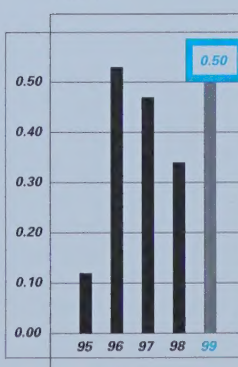
Production per Share
(MMcfeq/share)



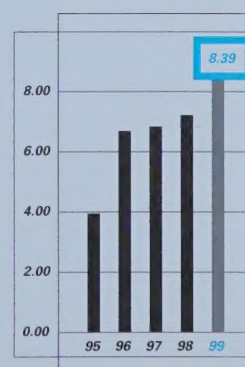
Cash Flow per Share
(\$/share)



Earnings per Share
(\$/share)



Net (Appraised) Asset Value
(\$/share)

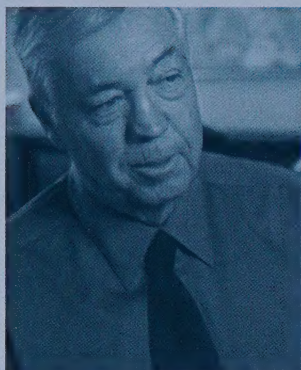


1999 highlights

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	1999	1998	% change
FINANCIAL (\$ millions except per share amounts)			
Gross Revenue	\$ 211.7	\$ 165.5	28
Cash Flow			
From operations	105.8	88.1	20
Per share	1.84	1.62	14
Earnings			
Net income	28.7	18.2	58
Per share	0.50	0.34	47
Capital Expenditures			
Exploration and development	139.9	153.9	(9)
Acquisitions (net of dispositions)	28.2	59.1	(52)
Other	(1.2)	(3.0)	60
Net Capital Expenditures	169.3	216.0	(22)
Total Assets	740.4	624.2	19
Long-Term Debt (net of working capital)	252.3	226.8	11
Shareholders' Equity	329.0	262.9	25
Weighted Average Common Shares Outstanding (000s)	57,529.0	54,348.0	6
Common Shares Outstanding at Year End (000s)	59,453.6	56,953.6	4
OPERATING			
Production			
Natural gas (MMcf/d)	220.0	203.5	8
Crude oil and liquids (Bbl/d)	1,854	1,988	(7)
Average Prices			
Natural gas (\$/Mcf)	2.43	2.02	20
Crude oil and liquids (\$/Bbl)	24.27	19.22	26
Reserves (proven and probable)			
Natural Gas Reserves (Bcf)			
Natural gas at year end before revisions	846.1	717.2	18
Revisions	(96.3)	71.0	(236)
Total natural gas reserves	749.8	788.2	(5)
Crude Oil and Liquids Reserves (MBbl)			
Crude oil and liquids at year end before revisions	11,306	13,301	(15)
Revisions	(2,426)	(1,671)	(45)
Total crude oil and liquids reserves	8,880	11,630	(24)
Land (thousands of acres)			
Total net land holdings	2,834	2,433	16
Net undeveloped land holdings	1,753	1,515	16
Drilling Activity			
Gas	94	111	(15)
Oil	9	24	(63)
Other	1	8	(88)
D&A	10	29	(66)
Total wells	114	172	(34)
Success rate	91%	83%	10%

president's message to shareholders



Paramount posted continued growth in its operational and financial statistics in 1999. Financial performance resulted in record revenue, cash flow and earnings levels, predominantly as a result of very strong natural gas prices. We are more certain than ever that the long awaited period of sustained strong natural gas pricing is finally upon us. Paramount has spent its twenty-year history positioning itself for what we believe was inevitable natural gas price increases, and we are now beginning to reap the rewards.

The supply side of the North American gas market appears to be experiencing accelerated decline rates and a more challenging environment for adding new reserves and deliverability, all at a time when demand continues to grow. Within Canada, where natural gas markets have shown the most dramatic strengthening in prices, pipeline receipts have been remarkably flat despite increased takeaway capacity in the form of new pipelines. This environment will be further

exaggerated as incremental pipeline capacity becomes available when the Alliance Pipeline

comes on stream in November 2000, further enhancing the unrestricted movement of gas from Western Canada to North American markets. Alberta spot prices are now in line with North American market hubs with transportation differentials at historic lows. Paramount is very bullish with respect to the North American natural gas business, and with over 90 percent of our production in the form of natural gas, we are experiencing good times and the future looks bright.

Financial Highlights

Paramount increased its 1999 natural gas production to 220 MMcf/d, a 7 percent increase over 1998 levels of 204 MMcf/d. Oil and natural gas liquids sales averaged 1,854 Bbl/d, 134 Bbl/d lower in 1999 in comparison to the previous year. Combined on a 10:1 basis, these resulted in production in 1999 of 239 MMcfq/d as compared 223 MMcfq/d in 1998, a 7 percent increase. Gas prices in 1999 were \$2.43/Mcf, 20 percent higher as compared to \$2.02/Mcf in 1998.

The combination of higher prices and production resulted in revenue growth of 28 percent to \$211.7 million. Cash flow was 20 percent higher in 1999 at \$105.8 million, or \$1.84 per share, as compared to \$88.1 million, or \$1.62 per share, in 1998. Earnings were \$28.7 million, or \$0.50 per share, in 1999, an increase of 58 percent in comparison to the \$18.2 million in 1998.

Exploration and Development

As has historically been the case for Paramount, our capital spending program was heavily weighted to the first quarter in 1999. Additional deliverability was added in both northeastern Alberta core areas with new plants at Sunday Creek and East Liege. Development projects in Northwest Alberta at Bistcho Lake and Pedigree also came on stream early in the second quarter. Year-round access in Central Alberta has allowed the Company to spread out a portion of its capital expenditure profile to historically less active periods of the year. Continuous drilling and tie-in programs at Kaybob and Kaybob North translated into production gains throughout 1999 and into 2000. In addition, two small gas plants were acquired at Cold Lake, and Paramount acquired partner interests at Clyde Lake, Winefred, Sunday Creek, Bistcho Lake and Legend East. Average daily production increased during each successive quarter in 1999, and significant further production increases are forecast for 2000. The bulk of the steady production increase is attributed to development activity in Central Alberta, while development activity in Northeast Alberta and Northwest Alberta offset production declines in these areas.

Paramount also made significant progress in its longer term, high impact exploration projects, particularly at Fort Liard in the Northwest Territories and East Lost Hills in California. Our exploration venture in Wyoming resulted in a dry hole, but further exploration on our considerable Wyoming land position is anticipated. In California, the Bellevue No. 1 well, which blew out in November 1998, was finally brought under control in May 1999. The relief well was subsequently whipstocked and drilled into the Temblor formation. Difficulty was again experienced during drilling and, therefore, terminated prematurely. A completion attempt was made and hydrocarbons were tested at limited rates. It is felt that the position of the well and the difficulties experienced during drilling and completion operations led to inconclusive results. Concurrently, a step-out well was spud in August 1999 which has just reached a final total depth of 19,724 feet in April 2000 and is currently being cased as a potential gas well. This well has successfully penetrated over 2,400 feet into the Temblor formation and experienced several very encouraging shows, with natural gas and condensate flared while drilling with very high mud weights. Completion operations in this well will commence in the second quarter of 2000. Paramount remains excited with regard to the potential of the East Lost Hills prospect and the significant exploration program we have committed to in the San Joaquin Basin.

In May 1999, Paramount announced its significant discovery in the Liard Basin of the Northwest Territories at the F-36 well which tested at combined rates of 45 MMcf/d of sweet gas from three separate intervals in the Mississippian Mattson formation. In late 1999, the find was offset by two development wells which unfortunately found only limited reserves. McDaniel & Associates now estimate the F-36 pool to contain 72 Bcf. On the positive side, Paramount re-entered a well along trend previously abandoned by a competitor, b-21-K/94-O-14 in Maxhamish, B.C., and successfully completed it in the Mississippian Mattson formation, the same formation productive in the F-36 discovery. A third structure drilled at b-43-K/94-O-14 also encountered what we believe to be commercial quantities of natural gas, so while the first discovery appears smaller than initially thought, there appear to be several more individual accumulations.

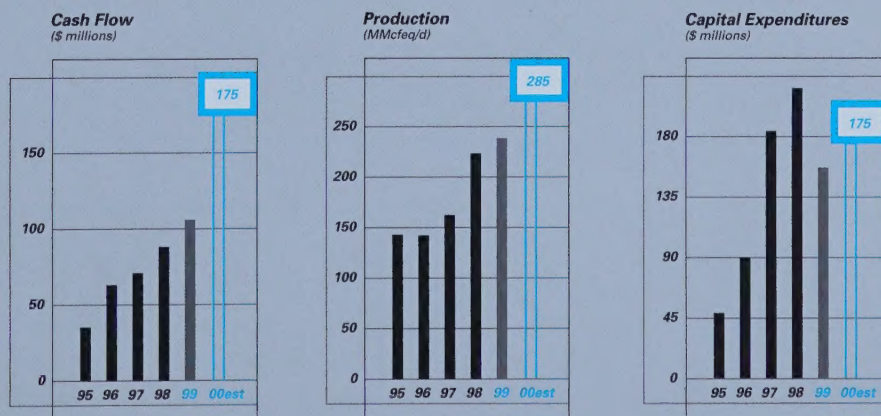
Paramount holds a 2.76 percent working interest in the Chevron-operated K-29 sour gas discovery well and the follow-up well at M-25. These wells are expected to begin production later this year.

Paramount shot a large seismic program in the Liard Basin this past winter which is currently being interpreted. Drilling will continue this year and next to test some of the many anomalies that have been identified in the Liard area.

2000 Forecast

Paramount successfully completed a self-marketed flow-through equity issue in October 1999 which saw 2.5 million shares issued at \$21.87 per share for proceeds of \$54.7 million. Proceeds from this equity issue were used to fund the aggressive winter 2000 capital program. Paramount has now completed this very active first quarter program, adding over 100 MMcf/d of net daily production. In northeastern Alberta, projects at Legend East and West Leismer added 20 MMcf/d of new production. In Central Alberta, new plants were brought on stream at Puskwa and Nosehill, which total a net 10 MMcf/d. Development projects at Kaybob North, Kaybob, Kaybob South and Pine Creek have added a further 30 MMcf/d of new production net to Paramount. In Northwest Alberta, Paramount has constructed and placed on stream three new gas plants at Assumption, Negus West and Negus East, adding 20 MMcf/d of net production capacity. In addition, development projects at Pedigree and Bistcho Lake will boost production an additional 10 MMcf/d. Also of note, a new discovery has been made at Hardy in southeast Saskatchewan with the first two wells contributing approximately 400 Bbl/d of light oil production net to Paramount.

Paramount has successfully navigated the regulatory regime, which has not been used for decades, to gain all the regulatory approvals needed to proceed to commercial production from the Liard Basin in the Northwest Territories. The Paramount-operated Liard project is the first new pipeline crossing the Northwest Territories border in decades, with production start-up expected in the second quarter of 2000. The Company has completed the construction of a 25-kilometer pipeline from a central site at F-36 south across the British Columbia/Northwest Territories border to a new Paramount-operated compression and liquids stabilization facility in Maxhamish, British Columbia. An additional 18 kilometers of pipeline connects the Liard/Maxhamish production into the north end of the Westcoast system at c-59-A/ 94-O-14. The Paramount-operated pipeline ties in F-36 and b-21-K to southern gas markets, and additional discoveries in the basin will be much easier to place on production. Thus, this milestone opens up the



Company's vast land position in this area to further development. The Paramount-operated Liard project as well as our small interest in the K-29 Liard discovery will initially produce at a rate net to Paramount of 15 to 20 MMcf/d.

Paramount is proud of the progress it has made for its shareholders with its exploration thrust into the southern Northwest Territories, and of the positive effect our activity has had on the local economy of the Liard area. The Company has been instrumental in providing jobs and positive economic impact to the community. Having successfully negotiated the regulatory regime gives Paramount valuable experience which will soon be applied at Cameron Hills also in the Northwest Territories, northeast of Paramount's Bistcho Lake project in Alberta. Paramount did pursue further testing in the Cameron Hills area during the first quarter of 2000 with encouraging results. Evaluation will continue through the spring of this year to identify the optimal scenario to bring these assets to a commercial development phase.

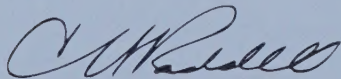
Changes in the Environment

Paramount, throughout its history, has diligently explored, developed, and subsequently produced from valid natural gas leases issued by the Province of Alberta in regions of northeastern Alberta which are coincident with bitumen leases issued by the Province to other operators. In 1998, prompted by a request by a bitumen lease owner to shut-in gas production in the Surmont Area of northeastern Alberta, the Alberta Energy and Utilities Board began a review and hearing process which has lasted for over a year. On April 3, 2000, the AEUB released its decision ordering the shut-in of a total of 146 gas wells, which in 75 gross wells Paramount holds an interest. This decision will directly impact Paramount's daily production by a net 22 MMcf/d as of May 1, 2000. Paramount is pursuing any and every avenue available to re-establish production from these wells. At the same time, the Company is seeking compensation for any and all damages which have occurred and will continue to occur as a result of this decision. A decision of this nature is unprecedented, and if not dealt with swiftly and fairly, it is Paramount's view that this decision has the potential to negatively affect the people of the Province of Alberta and the Alberta advantage which we have worked so hard to create. The decision was purported to be in the public interest. The quick resolution of the problems it created is very much in the public interest.

Outlook

Paramount wishes to thank Mr. Jim Jungé for his contribution as both a faithful shareholder and director for over 20 years as he retires from his position as a director of the Company. We wish him well in his future endeavors. We will welcome Dirk Jungé, Sue Rose and Jim Riddell to the Board at the annual meeting in June. We would also like to acknowledge the dedication of our staff and the significant contributions they have made through this transitional period of growth over the past two years. Paramount has successfully made the transition from one small independent to a consortium of small independent units, the lump sum of which is a company of substantial size with the potential for the continued growth that we have experienced in the past.

The outlook for Paramount continues to be bright. Our ability to adapt to the rapidly changing landscape in our business will be our most valuable asset going forward. Maintaining tight control of the pieces we can and influencing, as much as possible, those pieces which we cannot, will continue to be the difference which sets Paramount apart. Creatures which inhabit the remote regions of North America where Paramount conducts so many of its operations must constantly react to change, and Paramount will continue to rely on its adaptability as its competitive edge.



C. H. Riddell

President and Chairman of the Board

April 20, 2000

review of operations

Paramount's business strategy has served the Company's shareholders well over the past two decades of operations. This strategy remains relatively unchanged as we continue operations in the current attractive commodity price environment.

Paramount concentrates its exploration, development and acquisition activities in core operating areas where it can take advantage of previous infrastructure investment, production efficiencies, and experience. The Company's four core producing areas include: Northeast Alberta west of Highway 53; Northeast Alberta east of Highway 53; Central Alberta; and Northwest Alberta.

Within its core areas, the Company strives to maximize its working interest in low to medium risk exploration and development projects.

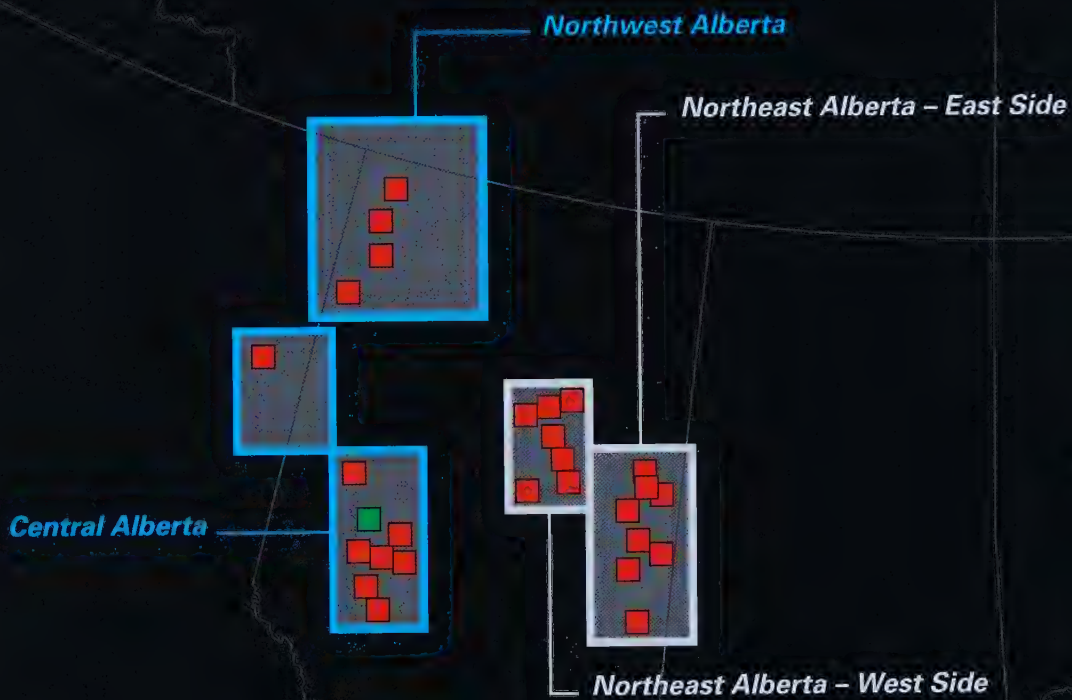
Joint venture relationships are utilized to expose the Company to higher risk, higher return opportunities both within and outside our established core areas.

The aggressive pursuit of complementary and strategic asset acquisitions is an important component in the Company's profitability equation.

Cost control is achieved through a rigorous budget process and close monitoring of general and administrative costs, field operating costs, and our capital programs.

Paramount is flexible, continually adapting to ever changing factors in our operating results and environment.

core producing properties



Northeast Alberta (West side)

drill depth		Less than 1,150 ft (350m)	
reservoir pressure		30 to 250 psi	
description		High deliverability shallow gas	
IP		500 to 5,000 Mcf/d	
undeveloped land		457,304 acres	
operating costs		\$0.45/Mcf	
formations	producing properties	average net 1999 production	average land working interest
Cretaceous: Wabiskaw McMurray	East Liege	5.7 MMcf/d	92%
	Legend	14.1 MMcf/d	88%
	Teepee Creek	9.3 MMcf/d	50%
Devonian: Wabamun Grosmont Nisku Leduc	South Liege	9.0 MMcf/d	94%
	Saleski	5.7 MMcf/d	92%
	North Liege	4.6 MMcf/d	91%
	Total	48.4 MMcf/d	
	2000 Production Forecast	51 MMcf/d	

Northeast Alberta (East side)

drill depth		Up to 1,475 ft (450m)	
reservoir pressure		85 to 320 psi	
description		Multi-objective Cretaceous shallow gas	
IP		250 to 2,000 Mcf/d	
undeveloped land		260,202 acres	
operating costs		\$0.39/Mcf	
formations	producing properties	average net 1999 production	average land working interest
Cretaceous: Grand Rapids Clearwater Wabiskaw McMurray	Bohn Lake	4.8 MMcf/d	33%
	Chard	3.5 MMcf/d	85%
	Clyde	2.2 MMcf/d	100%
	Cold Lake	17.1 MMcf/d	82%
	Corner	20.3 MMcf/d	100%
	Kettle River	24.9 MMcf/d	94%
	Leismer	3.5 MMcf/d	85%
	Quigley	10.1 MMcf/d	100%
	South Leismer	2.8 MMcf/d	100%
	Thornbury	6.9 MMcf/d	89%
	Winefred	7.1 MMcf/d	55%
	Other	2.0 MMcf/d	
	Total	105.2 MMcf/d	
	2000 Production Forecast	88 MMcf/d*	

*accounts for AEUB shut-in order

Central Alberta

drill depth		4,900 to 13,125 ft (1,500 to 4,000m)	
reservoir pressure		1,000 to 4,000 psi	
description		Multi-objective Cretaceous and Triassic gas and oil	
IP		250 to 10,000 Mcf/d	
undeveloped land		329,684 acres	
operating costs		\$0.50/Mcf	
formations	producing properties	average net 1999 production	average land working interest
Cretaceous: Belly River Cardium Dunvegan Viking Notikewin Spirit River Fahler Bluesky Gething Triassic: Charlie Lake Halfway Montney Devonian: Swan Hills	Kaybob	10.7 MMcf/d	90%
	Kaybob North	26.7 MMcf/d	75%
	Kaybob South	2.1 MMcf/d	80%
	Kaybob West	327 Bbl/d	100%
	Fox Creek	1.9 MMcf/d	100%
	Pine Creek	6.4 MMcf/d	67%
	Zaremba	5.5 MMcf/d	60%
	Other	0.5 MMcf/d	
	Total	57.1 MMcf/d	
	2000 Production Forecast	90 MMcf/d	

Northwest Alberta

drill depth		Up to 5,580 ft (1,700m)	
reservoir pressure		800 to 2,000 psi	
description		Moderate deliverability shallow gas through to high deliverability sour gas	
IP		500 to 10,000 Mcf/d	
undeveloped land		451,130 acres	
operating costs		\$0.56/Mcf	
formations	producing properties	average net 1999 production	average land working interest
Mississippian: Debolt Devonian: Slave Point Sulphur Point Keg River	Bistcho Lake	10.1 MMcf/d	80%
	Pedigree	3.3 MMcf/d	100%
	Sousa	0.8 MMcf/d	100%
	Total	14.2 MMcf/d	
	2000 Production Forecast	39 MMcf/d	

PRODUCTION

Total production rates in 1999 increased to 238.5 MMcfq/d as compared to 223.4 MMcfq/d in 1998, an increase of 7 percent year over year. Paramount continued to focus on its natural gas assets which represented over 92 percent of total sales. Recent diversification of our corporate asset base has been lowering our dependence on production from Northeast Alberta to the point where only 65 percent of total production in 1999 was attributable to these core areas. This shift in production is expected to continue through 2000. The remaining production was concentrated from our Central Alberta and Northwest Alberta growth core areas. Natural gas production increased 8 percent to 220.0 MMcf/d in 1999 from 203.5 MMcf/d in 1998. **A** Crude oil and natural gas liquids production decreased 7 percent or 134 Bbl/d, from 1,988 Bbl/d in 1998, to 1,854 Bbl/d in 1999. **B**

The Company posted four quarters of successive production increases in 1999. Although the Company achieved 8 percent average production growth, corporate production for 1999 was below forecast volumes due to a variety of factors. In Northeast Alberta, the Alberta Energy and Utilities Board (AEUB) Interim Directive 99-1, which resulted from a heavy oil lease owner challenging the inherent rights of natural gas lease holders to produce gas from the formations with prospective heavy oil reserves, has led to delays in bringing on new production from several of Paramount's core properties. Interim Directive 99-1 specifies that, for all wells drilled in the potential oil sands strata after July 1, 1998, an operator must submit an application to obtain AEUB approval before gas wells can be placed on production. The new approval process has had the overall effect of delaying production start-ups in the Northeast Alberta core areas. In Central Alberta, Paramount experienced higher than anticipated declines from the tight Cretaceous reservoirs which came on production over the past couple of years, affecting both gas and liquids production. In Northwest Alberta, Paramount was unsuccessful in securing additional plant capacity at Pedigree, thereby restricting production rates in this area to below forecast volumes. Oil production from our non-operated properties in southeastern Saskatchewan was also lower than anticipated.

Paramount currently forecasts 2000 natural gas production to average 260 MMcf/d and liquids production to average 2,500 Bbl/d. Our goal is to maintain production in the Northeast Alberta shallow gas core areas and grow production in Central and Northwest Alberta. The most significant production increases for 2000 are forecast from: new gas projects at Legend East and West Leismer in Northeast Alberta; new plants at Nosehill and Puskwa in Central Alberta as well as development projects at Kaybob, Kaybob North, Kaybob South and Pine Creek, as tie-ins are completed following the steady drilling program which commenced in the third quarter of 1999; Northwest Alberta, where three new gas plants are currently under construction; and the Liard Project in the Northwest Territories, scheduled to come on stream in April 2000.

Production Distribution (MMcfq/d) C	2000e	1999	1998
Northeast Alberta East Side	88	105	115
Northeast Alberta West Side	51	49	48
Central Alberta	90	57	37
Northwest Alberta	39	14	11
S.E. Saskatchewan/Other	17	14	13
Total	285	239	224



RESERVES

Paramount's reserves at year end 1999 increased 6 percent to 959.2 Bcfeq before negative revisions of 120.6 Bcfeq. The 1999 capital program resulted in reserve additions of 138.1 Bcf of natural gas and 351 MBbl of crude oil and natural gas liquids, or 141.6 Bcfeq, an increase of 17 percent from year end 1998. The net effect of the reserve additions, offset by the negative revisions and 1999 production of 87.1 Bcfeq, is a 7 percent reduction in total proved plus probable reserves to 838.6 Bcfeq at December 31, 1999 from 904.5 Bcfeq at year end 1998.

Proven and probable natural gas reserves decreased 5 percent at year end 1999 to 750 Bcf from a year end 1998 total of 788 Bcf.

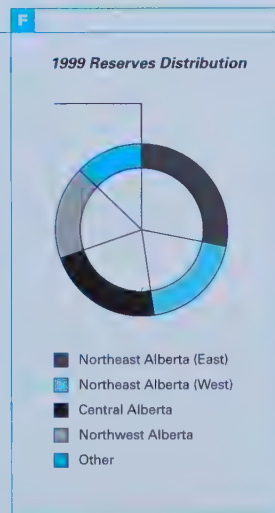
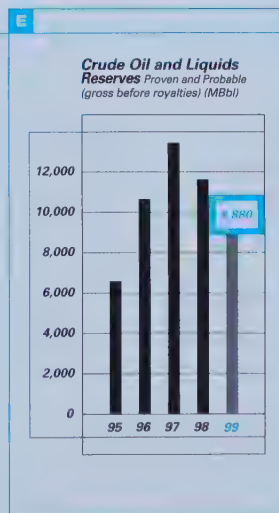
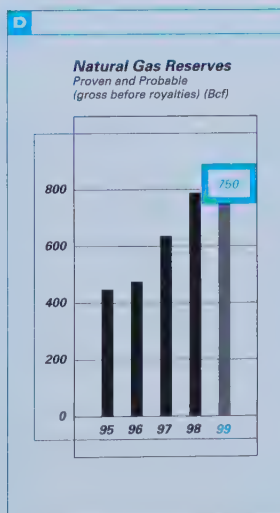
D Crude oil and natural gas liquids reserves decreased 2,751 MBbl, a 24 percent decrease from 11,630 MBbl at December 31, 1998 to 8,880 MBbl at year end 1999. **E** Natural gas reserves accounted for 90 percent of Paramount's reserve base as compared to 87 percent in 1998 and 83 percent in 1997. **F**

Of the total proven and probable reserve additions of 141.6 Bcfeq, 38.7 Bcfeq was added as a result of strategic acquisitions within the Company's four core areas, and 102.8 Bcfeq was the result of new exploration and development. The most significant negative revisions were concentrated in the non-operated Teepee Creek property, at Legend, Kaybob West, and at Legend East where a mathematical error had been made in 1998 with respect to the Company's working interest ownership of reserves.

On a proven plus probable basis, Paramount's reserve life index is 9.3 years for natural gas and 13.1 years for crude oil and natural gas liquids.

As in past years, Paramount's reserve evaluation and reporting was completed by two independent engineering firms at year end 1999. McDaniel & Associates Consultants Ltd. evaluated all of the Company's assets except for Midale, Saskatchewan. Gilbert Lautsen Jung Associates Ltd.'s evaluation was used in Midale, Saskatchewan, as they evaluate the reserves of the operator.

Natural Gas Reserves (Bcf)	1999		1998	
	Bcf	%	Bcf	%
Proven: Producing	370.9	49	412.8	52
Non-producing	223.8	30	194.5	25
Total proven	594.7	79	607.3	77
Probable additional	155.1	21	180.9	23
Total Proven and Probable	749.8	100	788.2	100
Crude Oil and Liquids Reserves (MBbl)	1999		1998	
	MBbl	%	MBbl	%
Proven: Producing	3,231	36	5,018	43
Non-producing	3,033	34	2,877	25
Total Proven	6,264	70	7,895	68
Probable additional	2,616	30	3,735	32
Total Proven and Probable	8,880	100	11,630	100



PROFITABILITY

Paramount's business strategy includes a strong and continual focus on economics and profitability. Every employee's mandate is to turn ideas, whether geological, technical, strategic, marketing related or otherwise, into value for our shareholders. In combination with cost control, the result of this strategy is a history of positive earnings, and sustained growth in earnings per share.

Natural Gas and Crude Oil Prices

The Canadian oil and gas industry experienced strong increases in commodity prices in 1999. Paramount realized an average plant gate natural gas sales price of \$2.43/Mcf in 1999, an increase of 20 percent from \$2.02/Mcf in 1998. Crude oil and liquids prices averaged \$24.27/Bbl in 1999 compared to \$19.22/Bbl in 1998, an increase of 26 percent year over year.

TransCanada Pipeline's new intra-Alberta toll structure came into effect on April 1, 2000. A significant number of the Company's producing gas properties are located in the more distal segments of the Alberta sales gas transmission infrastructure where Paramount expects transportation charges to increase up to \$0.10 – 0.12/Mcf over the next three year period.

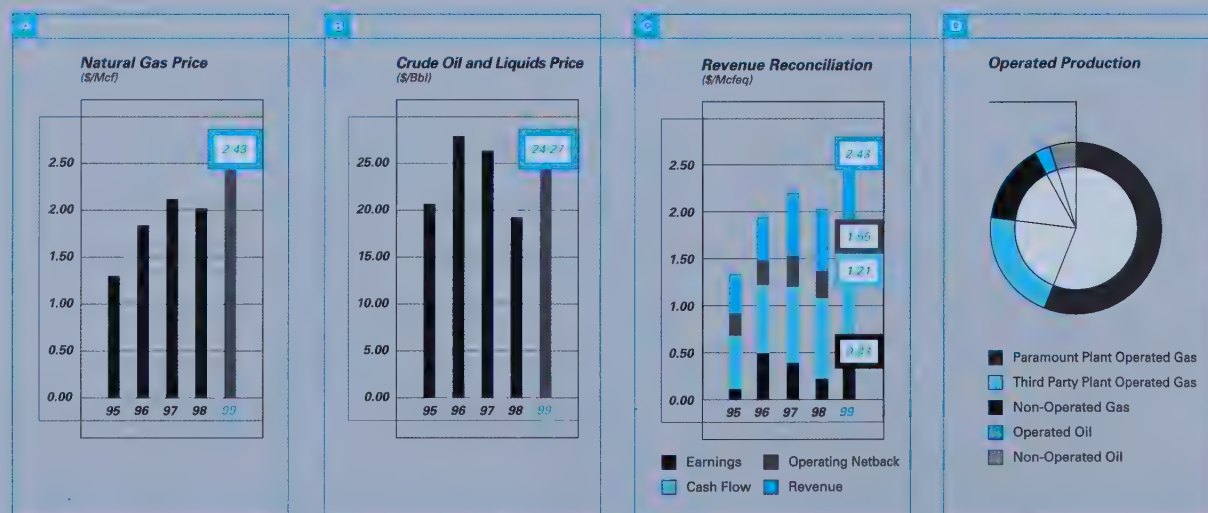
The forward strip for natural gas suggests prices will continue to strengthen throughout the year 2000. Paramount is forecasting plant gate natural gas prices in 2000 to average \$2.95/Mcf.

Revenue Reconciliation

Strong commodity prices in combination with production growth translated into record financial results for Paramount in 1999. The Company recorded gross petroleum and natural gas sales revenue of \$211.7 million, an increase of \$46.2 million, or 28 percent, year over year. Nearly 25 percent of the growth in revenue is due to increased sales volumes, with the balance generated from higher natural gas and crude oil prices.

Revenue Variance Analysis (\$ millions)	1999	1998
Volume increase (decrease)	11.1	48.9
Price increase (decrease)	34.8	(13.9)
Net revenue change	46.2	35.0

Cash flow increased \$17.7 million, or 20 percent, to a record \$105.8 million in 1999. Cash flow per share increased to \$1.84, up 14 percent from \$1.62 per share in 1998. Earnings totalled \$28.7 million, a 58 percent increase from \$18.2 million in 1998. Earnings per share increased 47 percent year over year to \$0.50 per share.



Cash Flow Reconciliation C	1999		1998	
Volume (MMcfeq) ⁽¹⁾	87,067		81,597	
	\$ Million	\$/Mcfeq	\$ Million	\$/Mcfeq
Gross Revenue	\$ 211.7	\$ 2.43	\$ 165.5	\$ 2.03
Net royalty	(37.6)	(0.43)	(20.9)	(0.26)
Operating costs	(39.0)	(0.45)	(33.0)	(0.40)
Operating netback	135.1	1.55	111.6	1.37
G&A and other expense (net)	(8.6)	(0.10)	(4.5)	(0.05)
Interest on long-term debt	(15.0)	(0.17)	(12.7)	(0.16)
Lease rentals	(4.1)	(0.05)	(4.2)	(0.05)
Large Corporation/Current taxes	(1.6)	(0.02)	(2.1)	(0.03)
Cash flow	\$ 105.8	\$ 1.21	\$ 88.1	\$ 1.08
Weighted average shares (millions)	57.5		54.3	
Cash flow per share	\$ 1.84		\$ 1.62	

⁽¹⁾ MMcfeq: barrels of oil converted to gas sales on the basis of 1 barrel = 10 Mcf.

Operated Plant Capacity

Operated net plant capacity increased 7 percent in 1999 to 167 MMcf/d. This is primarily the result of the construction of the East Liege facility, compression additions at Bistcho Lake and Kaybob, the purchase of two facilities at Cold Lake, and the acquisition of additional working interest at Bistcho Lake, Leismer and Clyde Lake.

Operated Plant Capacity ⁽¹⁾ (Defined as at December 31)	1999	1998
Number of gas plants	16	15
Net plant capacity (MMcf/d)	167	156
Gross plant capacity (MMcf/d)	212	200

⁽¹⁾ Capacity is defined as 'best month' production unencumbered by transportation restriction per plant per year.

Total Company operating costs averaged \$0.45/Mcfeq, an increase of 12 percent, or \$0.05/Mcfeq, over 1998 levels. Paramount operated 84 percent, or 184 MMcf/d, of its natural gas production and 43 percent, or 789 Bbl/d, of crude oil and liquids production in 1999. Operated production is defined as production from wells in which Paramount is the designated operator, including Paramount-operated wells which are processed through third party facilities. **D**

Wherever economically justifiable, the Company controls our throughput and costs with construction of Paramount-operated facilities versus third party processing. However, third party processing facilities are utilized in situations where that proves to be the optimal development scenario for a given project. The majority of our third party processing fees are paid in Central Alberta, where industry has established a significant gas processing grid. **Factoring out the Company's use of third party processing facilities, Paramount actually produced 135 MMcf/d, or 61 percent of our total natural gas production through Paramount-operated facilities. Operating costs at these facilities averaged \$0.40/Mcfeq.**

Paramount has historically recorded operating costs well below the industry average from our Northeast Alberta shallow gas core areas. Since the majority of the operating costs at a given facility are fixed, as throughput decreases per unit operating costs will increase. With production declines in many of our depreciated Northeast Alberta gas plants, per unit operating costs are higher than in past years. As we gain experience and reach a critical mass with respect to operations in our growth areas in Central and Northwest Alberta, we expect per unit operating costs in these areas to mimic our track record of low cost production from high deliverability shallow gas in Northeast Alberta.

Net Asset Value

Paramount's net appraised asset value at year end 1999 increased 21 percent to \$498.7 million, or \$8.39 per share. A 17 percent increase in the estimated value of the Company's assets was achieved by only a 10 percent increase in net debt to realize this growth in value. Paramount utilizes debt funding as leverage to add shareholder value. Prudent debt financing will continue to be a key component of Paramount's capitalization, as we believe this leverage will translate into additional value for the Company as reserves are booked and cash flow is realized in the current attractive commodity price environment.

Net (Appraised) Asset Value (\$ millions as at December 31)	1999	1998
Reserve value, before royalties ⁽¹⁾	675.7	570.7
Alberta Royalty Tax Credit (ARTC) ⁽¹⁾⁽²⁾	4.0	6.5
Fair market value of undeveloped land	71.4	63.0
Subtotal B	751.1	640.2
Working capital (deficiency)	16.4	(2.3)
Total Assets	767.5	637.9
Long term debt (operating)	(268.8)	(226.4)
Net (Appraised) Asset Value	498.7	411.5
Net (Appraised) Asset Value per Share ⁽³⁾	\$ 8.39	\$ 7.22

⁽¹⁾ @ 15 percent discount

⁽²⁾ ARTC: only on proven reserves

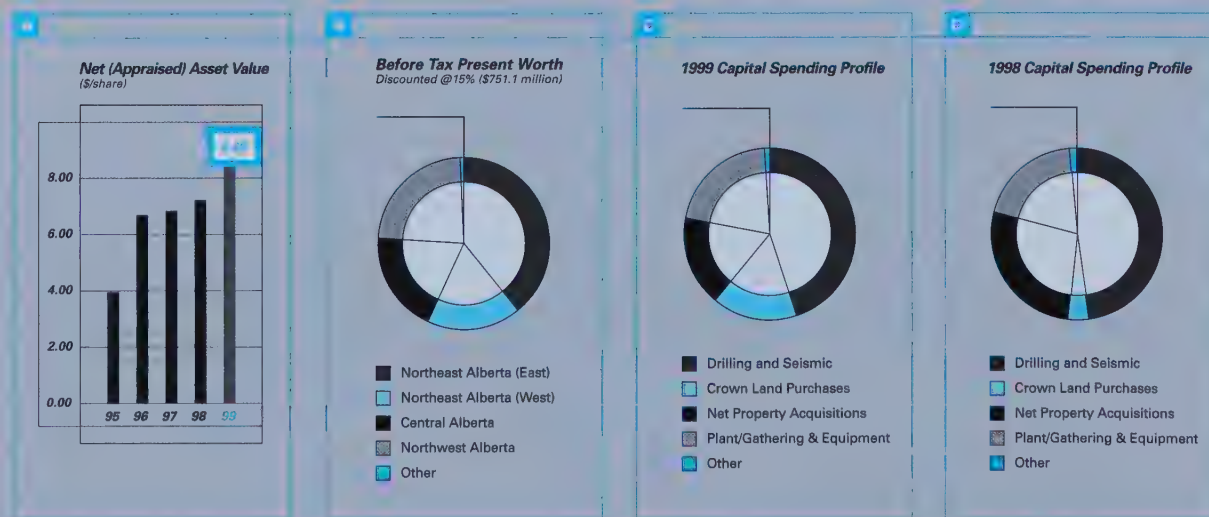
⁽³⁾ Outstanding shares: 1999 – 59,453,600; 1998 – 56,953,600

CAPITAL EXPENDITURES

Net capital expenditures in 1999 totalled \$156.8 million, a decrease of 27 percent from 1998 net capital spending levels of \$216.0 million. This total capital reflects a \$14.3 million credit for the tax effect of renounced exploration and development expenditures which resulted from the October 2000 flow-through share issue. A net \$30.0 million, or 18 percent, focused on asset rationalization, the largest being a transaction with a non-industry partner where Paramount acquired additional working interest in existing Paramount-operated properties.

Gross exploration and development capital expenditures totalled \$139.9 million, \$103.4 million (74 percent) of which was devoted to drilling, geological and geophysical activities, and Crown land purchases. The remaining \$36.5 million was spent on production equipment and facilities in our core producing areas. This mix of capital spending in 1999 was very similar to our concentration of capital in 1998, with the exception of the decrease in asset acquisitions which was offset by a significant increase in crown land purchases.

Paramount exposed itself to an unprecedented level of pure exploration in 1999, dedicating 20 percent of its capital budget to this future growth potential. Along with exploration activity within established core areas, the Company continued to operate its extensive exploration



program in the Liard Basin of the Northwest Territories, and to participate in a large joint venture in the San Joaquin Basin in California. In addition, a number of potentially high impact plays were drilled in late 1999, the results of which will be forthcoming as completion and testing operations progress.

The Company has budgeted for projects requiring \$175 million of capital in 2000, excluding any opportunities for strategic acquisitions which may arise.

Drilling

Paramount participated in a total of 114 gross wells (86.1 net) in 1999 for a success rate of over 91 percent. **E F** (pg. 18) The majority of the Company's lower working interest participation was in high risk plays in California and Liard in the Northwest Territories, and within established partnerships in Southeast Saskatchewan, Northeast B.C. and north of Zama in Northwest Alberta.

The total number of wells drilled in 1999 was down 34 percent from 1998 levels primarily due to a significant reduction in drilling in our Northeast Alberta shallow gas core area. The AEUB Interim Directive 99-1 is partly responsible for this reduction in drilling. With the uncertainty inherent in the approval process, Paramount deferred drilling in some regions until the AEUB reached further decisions about the production of gas in the vicinity of bitumen leases.

Despite AEUB Interim Directive 99-1, the Company still drilled the majority of its wells in 1999 in the Northeast Alberta shallow gas core areas, where 53 gross (45.2 net) wells were drilled. In the Central Alberta core area 38 gross (29.5 net) wells were drilled; 9 gross (6.6 net) wells were drilled in Northwest Alberta; and 3 gross (0.8 net) wells were drilled in Southeast Saskatchewan. An additional 11 gross (4.0 net) new pool wildcats were drilled on numerous prospects outside the Company's established core areas.

Drilling Results	1999		1998	
	Gross	Net	Gross	Net
Exploratory				
Gas	42	31.3	59	38.1
Oil	1	0.3	13	2.9
Standing	1	0.4	6	3.6
Service	1	0.1	0	0.0
D&A	7	5.7	25	11.8
Total Exploratory	52	37.7	103	56.4
Success rate (gross)	86%		76%	
Development				
Gas	50	41.9	50	36.3
Oil/oil and gas	8	4.0	10	3.9
Standing	1	0.5	5	3.8
Service	0	0.0	0	0.0
D&A	3	2.0	4	3.5
Total development	62	48.4	69	47.5
Success rate (gross)	95%		94%	
All well categories	114	86.1	172	103.9
Success rate (gross)	91%		83%	

Seismic

With the Company's diversification and concentration of activity outside of our Northeast Alberta shallow gas core areas, a key component in Paramount's exploration and exploitation strategy is the cost-effective acquisition and skillful interpretation of high resolution seismic data to maximize our drilling success rate and explore for new prospects. **During 1999, Paramount acquired 3,145 kilometers of 2D and 300 square kilometers of 3D seismic data.** In addition, several strategic agreements were negotiated to give Paramount access to large volumes of low cost, high quality seismic trade data.

Land

Paramount's land inventory at year end 1999 totalled 2.8 million net acres, an increase of 16 percent from December 31, 1998. **G** With attractive commodity prices, land acquisitions became significantly more competitive in 1999 as compared to the lower commodity price environment for 1998. The Company spent \$27.7 million on Crown and freehold land purchases in 1999, a 226 percent increase over 1998 land expenditures totalling \$8.5 million.

Paramount increased its undeveloped land holdings proportionately to the total land base, growing 15 percent to 1.7 million net acres over the 12 month period ending December 31, 1999. The Company's undeveloped land inventory is shifting from our traditional shallow gas areas to new growth areas in Central Alberta, Northwest Alberta and the Liard Basin in the Northwest Territories. **H**

Land (thousand acres)	1999		1998	
	Gross	Net	Gross	Net
Land assigned reserves	1,539	1,081 (38%)	1,356	917 (38%)
Undeveloped land	2,834	1,753 (62%)	2,674	1,516 (62%)
Total	4,373	2,834	4,030	2,433
Value of undeveloped land @ FMV (\$ millions)	\$ 71.4		\$ 63.0	

FINDING AND DEVELOPMENT COSTS

As Paramount is a full cycle exploration and development company, we believe that the historical rolling average approach to finding and onstream costs is more representative of true performance. For any given project, reserve additions are not necessarily booked in the same year that the bulk of the development capital is expended.

Paramount calculates finding and development costs through the following formula:

Total capital expenditures - disposition proceeds ± change in fair market value of undeveloped lands
Proven and 50% probable reserve additions (oil to gas conversion of 1 barrel = 10 Mcf)

Paramount's finding and development costs on a five-year rolling average basis for the period from 1995 through to 1999 are \$1.06 per Mcfeq. The negative reserve revisions in 1999, coupled with extensive capital expenditures in the San Joaquin Basin exploration projects where no reserves were booked in 1999, significantly skewed this calculation.



Paramount is committed to exploration as the future growth engine for the Company. We proactively participate in two distinct levels of exploration activity: Core Area Exploration, evaluating new plays, prospects and opportunities within our traditional core operating areas; and Pure Exploration, identifying new exploration opportunities outside of our established play areas and/or within geological horizons with previously unrecognized potential. The Company has an extensive, and continually evolving inventory of prospects at various stages of evaluation. Successful prospects are delineated, subsequently developed and placed on production, culminating in the expansion of an established core region or the creation of a new core operating area.

In 1999, over 20 percent of the annual capital budget was dedicated to Pure Exploration, with additional expenditures directed to land purchases, exploratory drilling and geophysical activities within our four traditional core areas. Current exploration activity outside of established core areas is primarily focused in the Liard Basin in the Northwest Territories and Northeast British Columbia, the Southern Alberta Foothills, the Powder River Basin in Wyoming, and the San Joaquin Basin in California.

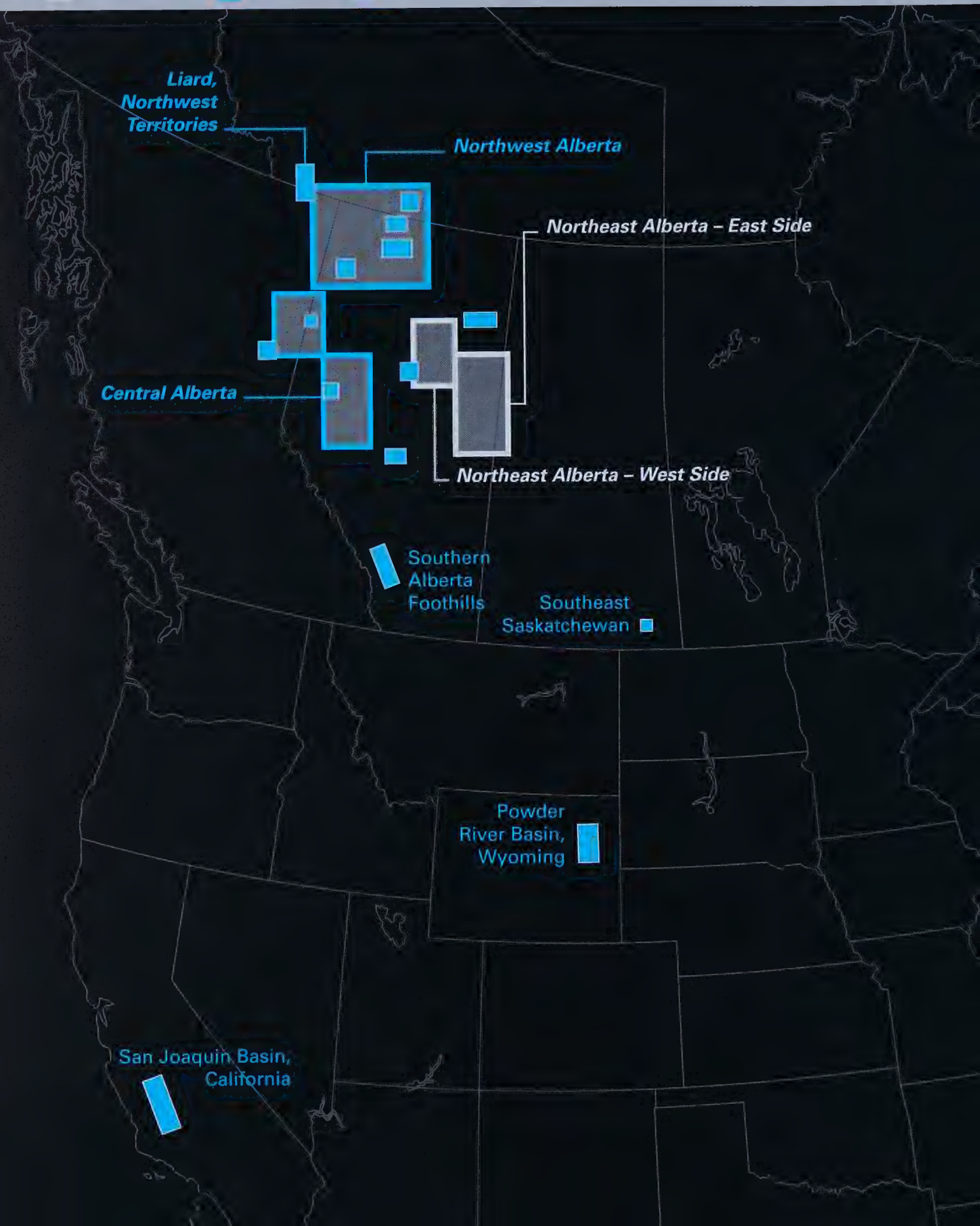
Paramount's exploration inventory includes both new concept play types and existing ideas applied to new areas or geological formations.

The Company strives to tie up large land positions which could be potentially proved up by our exploration expenditures. This gives the Company the ability to capitalize on success quickly and economically.

Working interest is maximized in low cost exploration ventures and medium to high risk/high reward opportunities located such that the exploration to production cycles could be relatively short.

Paramount utilizes technically advanced drilling systems specific to each play type to ensure accurate evaluation of the target zones.

Paramount is committed to utilizing innovative, as well as proven technologies to reduce the inherent risks in the exploration process, while maximizing return on invested capital.



***Our mandate is to
effectively manage
our risk and to provide
a strategic element of
stability and
predictability
in our continuing
exploration pursuits***

Pure Exploration Prospect Inventory

Exploration Project	Description	Average Working Interest
Liard Basin	Multi-zone Cretaceous, Mississippian and Devonian structural and stratigraphic traps Drilling depths up to 11,150 ft (3,400m)	3 – 50%
San Joaquin Basin	Deep structural gas/oil play targeting thick Tertiary sands Drilling depths up to 20,000 ft (6,000m)	10 – 25%
Southeast Saskatchewan	Multi-zone Devonian to Ordovician oil Drilling depths up to 9,900 ft (3,000m)	25%
Powder River Basin	Cretaceous stratigraphic traps and sub-thrust plays Drilling depths up to 16,000 ft (4,900m)	55%
Southern Alberta Foothills	Cretaceous, Mississippian and Devonian thrust faulted targets Drilling depths up to 16,400 ft (5,000m)	20 – 25%
Shallow Gas	Paleozoic subcrop and Cretaceous stratigraphic gas traps Drilling depths less than 2,000 ft (600m)	45 – 100%



name

Liard Basin, NWT

discovery well

F-36 – 60°10' N 123°15' W

discovery date

2/5/1999

average drill depth

7,200 ft (2,200 m)

target zones

Mississippian Mattson

average working interest

50%

anticipated well deliverability

10-25 MMcf/d

prospect reserve potential

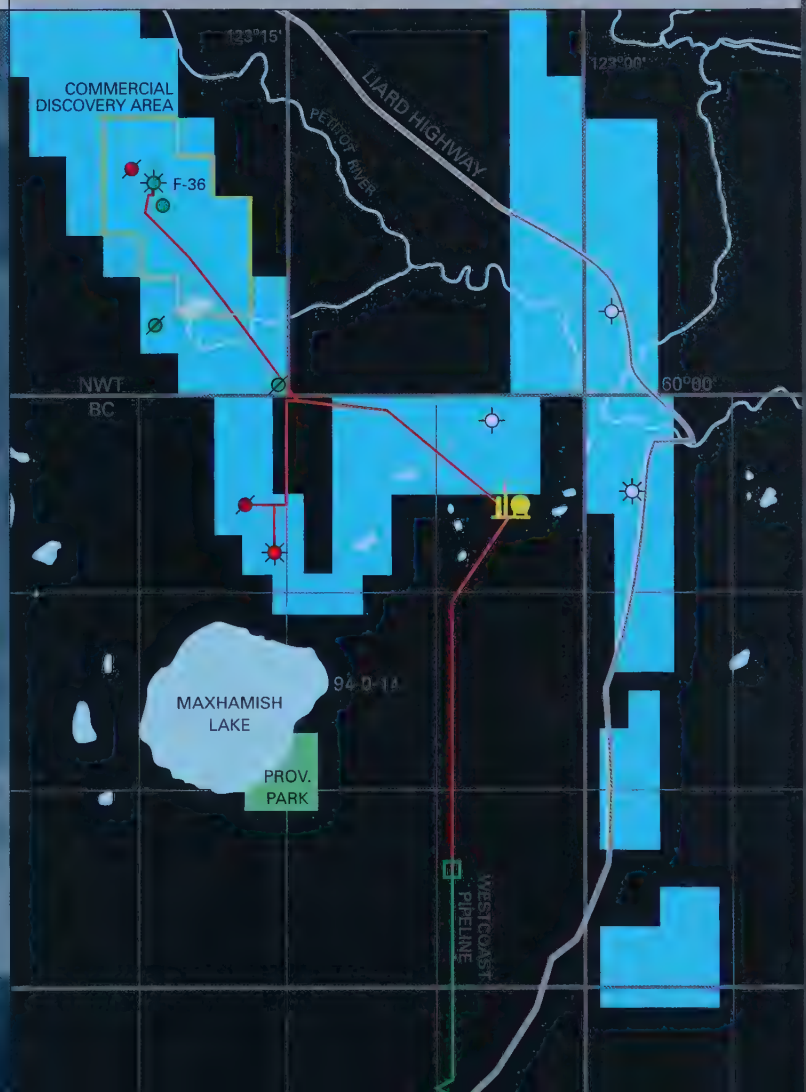
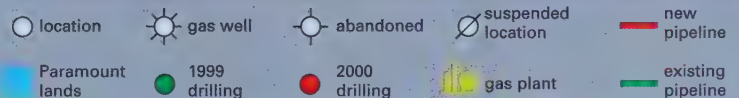
50-100 Bcf

anticipated initial production

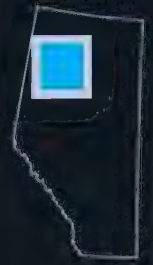
Q2 2000

play description

Two stepout wells offsetting the initial F-36 sweet gas discovery well were drilled last winter at 0-35 and 1-46 and both encountered gas and water. An abandoned wellbore at b-21-K/94-0-14 was re-entered and completed as a gas well. A new location at b-43-K/94-0-14 was drilled and completion operations were suspended due to break-up. A 16 mile pipeline was constructed from F-36 to a new Paramount-operated gas plant in Maxhamish, B.C. An additional 11 miles of pipeline was built to connect this facility to the north end of the Westcoast system.







name **Negus/Assumption**

discovery well **10-2-112-1W6**

discovery date **1989**

average drill depth **250 – 900 ft
(75 – 275 m)**

target zones **Cretaceous**

average working interest **100%**

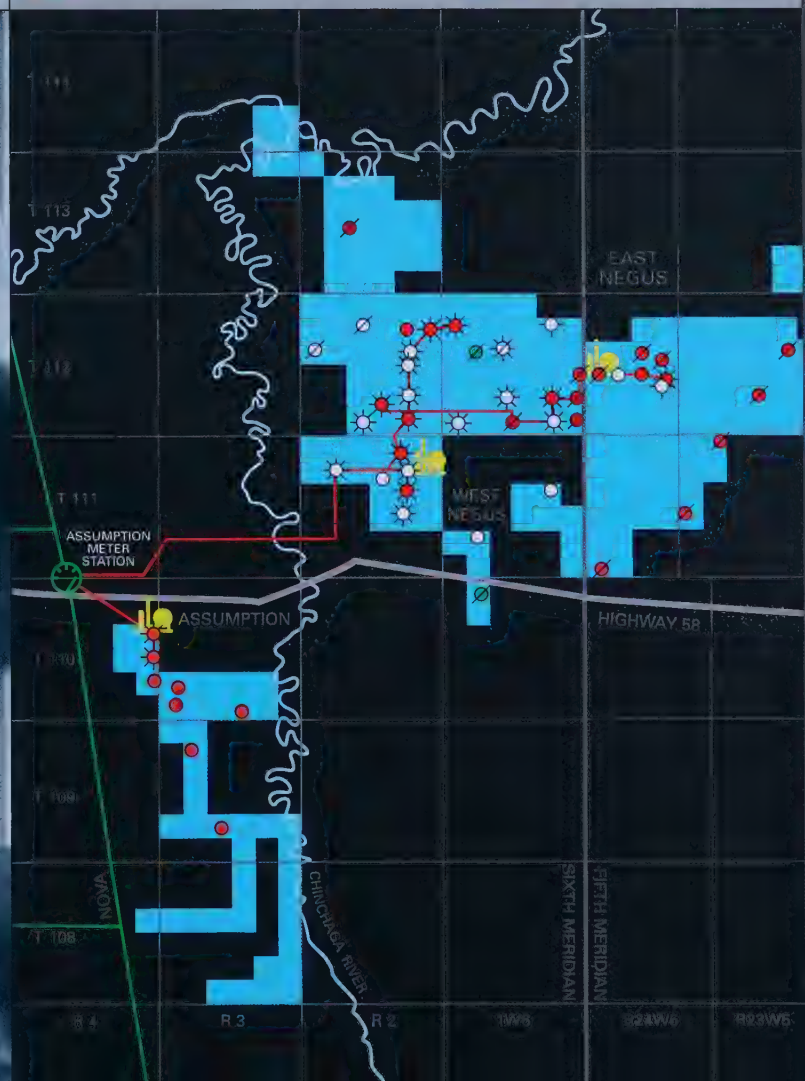
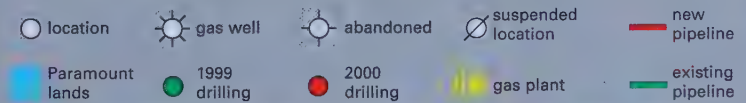
anticipated well deliverability **150 – 4,000 Mcf/d**

prospect reserve potential **10-20 Bcf**

anticipated initial production **4/12/2000**

play description

Paramount has secured over 83,992 gross acres (98.5% net) in the Negus/Assumption area to exploit sweet, low pressure natural gas reserves from Cretaceous strata. In the first quarter of 2000, 8 exploration and/or delineation wells were drilled on the Assumption land block and 24 wells were drilled at Negus. Paramount constructed three gas plants, 20 miles of low pressure gathering system, and 34 miles of sales gas pipeline across the Chinchaga River for gross processing capacity of 25 to 30 MMcf/d.





name

legend east

lead well

15-1-92-17W4

discovery date

1/17/1995

average drill depth

165 ft (250m)

target zones

**Cretaceous Wabiskaw,
McMurray**

average working interest

100%

anticipated well deliverability

900 Mcf/d

prospect reserve potential

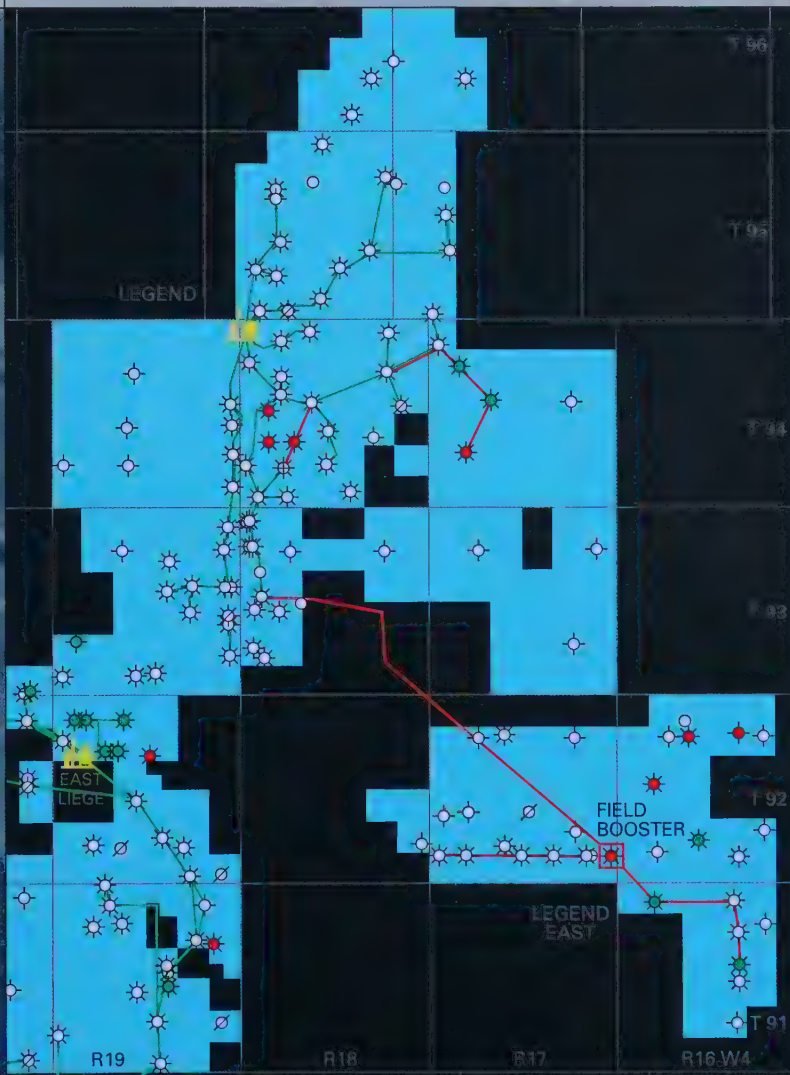
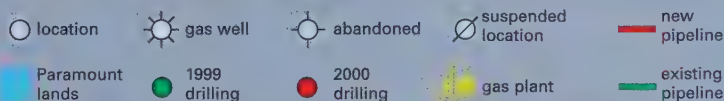
25 Bcf

anticipated initial production

3/1/2000

play description

The Legend East project has been ongoing for several years, following up the 1995 discovery of low pressure shallow gas reserves in the Cretaceous Wabiskaw and McMurray formations with 10 successful delineation wells. Gas from this pool was tied in during the first quarter of 2000 with 8 miles of low pressure gathering system, a field booster, and 15 miles of high pressure pipeline to the Paramount-operated Legend plant. This 100% Paramount project is expected to flow at initial rates of 10 MMcf/d. Three new wells were drilled at Legend East to delineate additional reserves, two of which encountered gas.







name

nosehill

discovery well

02/11-19-55-20W5

discovery date

12/26/1999

average drill depth

13,125 ft (4,000m)

target zones

Devonian Leduc Reef

average working interest

100%

anticipated well deliverability

5 MMcf/d

prospect reserve potential

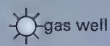
30 Bcf

anticipated initial production

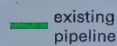
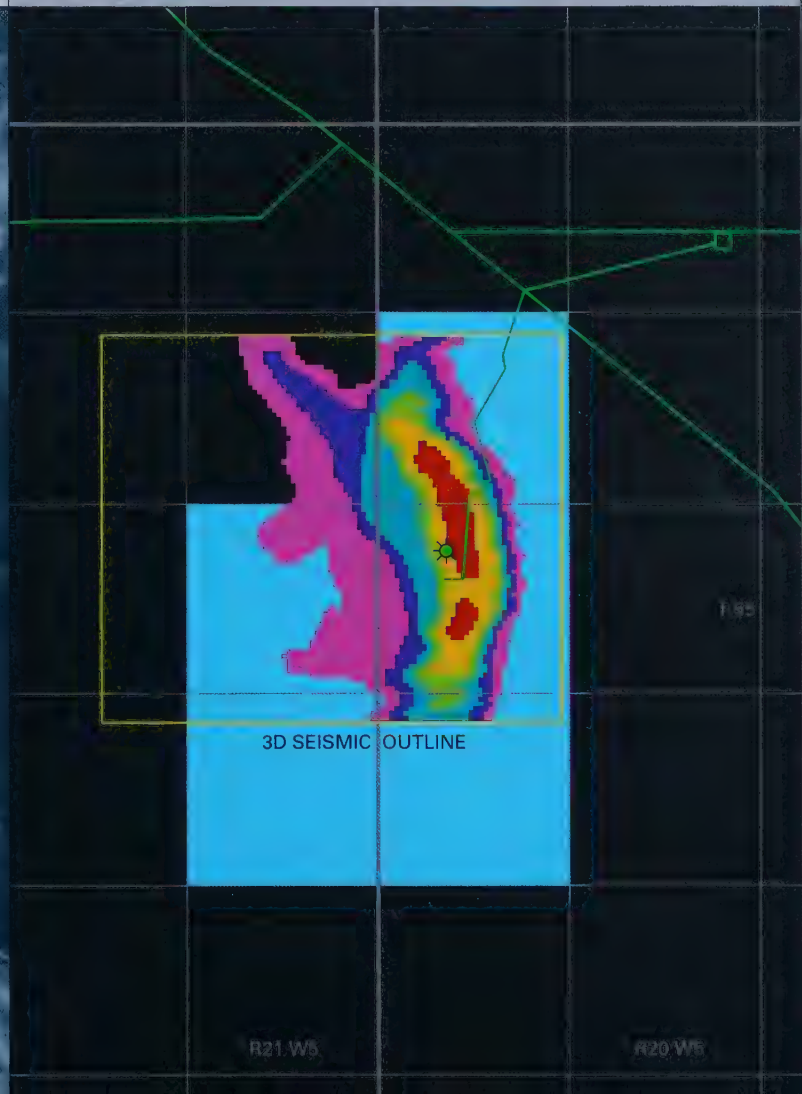
4/5/2000

play description

The Nosehill well targeted a high pressure, sweet gas charged Leduc pinnacle reef. The prospect was identified on 2-D seismic then detailed with 3-D seismic. Tie-in was completed in the first quarter of 2000. The dry gas is choked from a wellhead flowing pressure of over 3000 psi to Nova pressure of approximately 1,000 psi without further processing. The Nova tie-in point is adjacent to the 11-19 wellsite. One follow-up development location remains on this prospect.



gas well

existing
pipelineParamount
lands1999
drilling





name **San Joaquin Basin, California**

discovery well **Bellevue East Lost Hills #1 – 17 blow-out**

discovery date **11/24/1998**

average depth **18,000 ft (5,500m)**

target zones **Tertiary Temblor**

average working interest **12%**

anticipated well deliverability **25 MMcf/d**

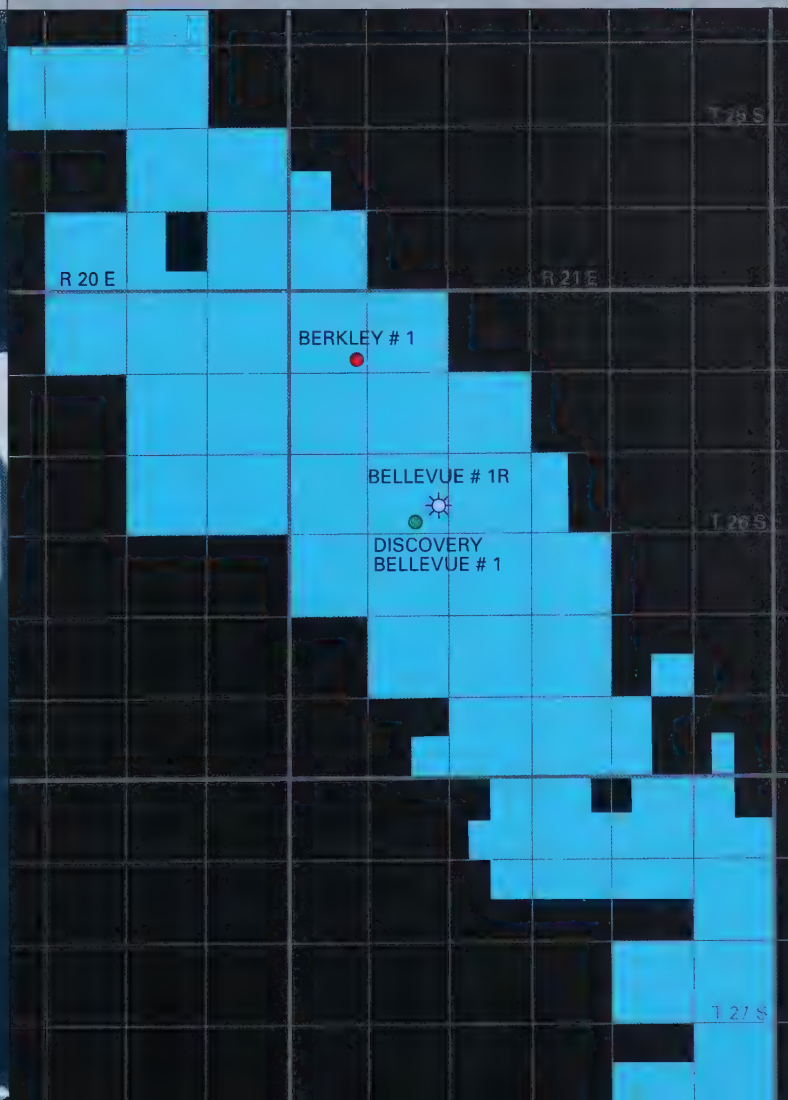
prospect reserve potential **350 million
– 1 billion BOE**

anticipated initial production **2001**

play description

The East Lost Hills prospect targets structurally trapped gas sands of the Tertiary Temblor formation. Intense faulting and fracturing enhances the reservoir quality of these deeply buried sands. The trap area as defined by seismic could be up to 25 square miles. The reservoir is highly over pressured and requires great care in drilling as was learned from the discovery well which blew out at an approximate rate of 100 MMcf/d. Bellevue #1R was drilled as a replacement well in May 1999 but was unable to evaluate the blow-out zone due to mechanical difficulties. Berkley #1 spud in August 1999, is cased to TD at 19,724 feet, and is currently waiting on completion.

○ location ☼ gas well ● 1999 drilling ● 2000 drilling ■ Paramount lands



100%

accountability

*a 20 year history of
positive earnings proves
that Paramount is
committed to maximizing
shareholder value*

management's discussion & analysis

HIGHLIGHTS

Paramount's corporate growth strategy has focused almost exclusively on the exploration, development and production of natural gas in Alberta, British Columbia, the Northwest Territories and California. This strategy has been complemented by key property acquisitions and the accumulation of a significant undeveloped land base, providing additional opportunity for future growth. Activity levels and the Company's operating results have been significantly impacted by this emphasis.

- Paramount is highly leveraged to natural gas with 92 percent of revenue from this source
- Production increased 7 percent to average 238.5 MMcf of natural gas equivalent per day
- Cash flow increased 20 percent to \$105.8 million
- Net earnings totalled \$28.7 million
- Exploration and development capital expenditures totalled \$139.9 million

For the purpose of comparing the Company's revenues and costs on a unit-of-production basis, crude oil and liquids volumes have been converted to natural gas (Mcf) on the basis that one barrel of oil equals 10 Mcf of gas.

ACCOUNTING POLICY

Paramount follows the "successful efforts" method of accounting for its petroleum and natural gas operations. This method, unlike the alternative full cost accounting method, usually generates a more conservative value for net earnings and cash flow as exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases and abandoned wells, are expensed rather than capitalized in the year incurred. However, to make reported cash flow results comparable to industry practice, Paramount reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities.

REVENUE

Production Revenue (\$ thousands)	1999	1998	1997
Natural gas	\$ 195,640	\$ 151,412	\$ 115,096
Crude oil and natural gas liquids	16,018	14,115	13,397
	\$ 211,658	\$ 165,527	\$ 128,493

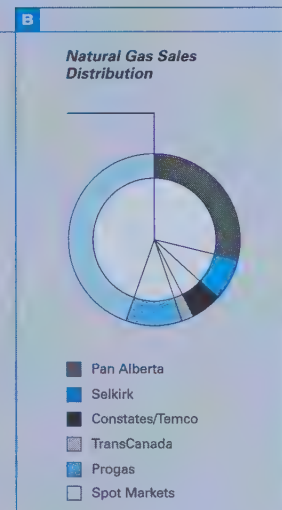
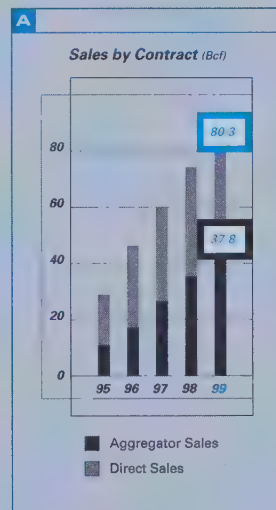
Petroleum and natural gas revenue increased 28 percent in 1999 to \$211.7 million from \$165.5 million in 1998 (1997 – \$128.5 million), due to a 20 percent increase in product prices and a 7 percent increase in production volumes. Paramount's 1999 production profile was significantly weighted to natural gas with over 90 percent of Company sales attributable to this commodity.

Natural gas sales increased 8 percent to 220.0 MMcf/d in 1999 from 203.5 MMcf/d in 1998 (1997 – 148.6 MMcf/d). Paramount's natural gas sales price averaged \$2.43 per Mcf in 1999 as compared to \$2.02 per Mcf in 1998 (1997 – \$2.12 per Mcf).

During 1999 approximately 55 percent of Paramount's natural gas sales were to long-term contracts sold through gas aggregators and direct sales purchasers as compared to 60 percent and 62 percent for 1998 and 1997, respectively.

Natural Gas Sales per Market Group A B		1999		1998		1997	
		Bcf	%	Bcf	%	Bcf	%
Aggregator contracts							
Pan Alberta	Midwestern U.S., the U.S. Pacific Northwest, California and Quebec	23.1	28.8	25.7	34.6	17.9	33.0
Progas	Northeastern U. S.	8.4	10.6	8.8	11.8	5.0	9.2
Canstates/Temco	Northeastern U. S.	4.5	5.7	4.3	5.8	4.7	8.7
TransCanada	Eastern Canada	1.8	2.3	—	—	—	—
Subtotal		37.8	47.4	38.8	52.2	27.6	50.9
Direct sales							
Direct sales Selkirk	New York State	6.3	8.0	6.0	8.1	6.0	11.1
Spot – California		15.5	19.6	11.6	15.6	11.2	20.7
Spot – Waddington		7.2	9.0	7.2	9.7	7.2	13.3
Spot – Alberta/B.C.		13.5	14.0	10.7	14.4	2.2	4.0
Total		80.3	100.0	74.3	100.0	54.2	100.0

Natural Gas Sales Distribution (% of total sales)



The Company's average liquids price in 1999 increased 26 percent to \$24.27 per barrel from \$19.22 per barrel in 1998 (1997 – \$26.36 per barrel), consistent with a 34 percent increase in the average West Texas Intermediate ("WTI") price. The WTI price for crude oil averaged U.S. \$19.26 per barrel during 1999, up from U.S. \$14.40 per barrel in 1998 (1997 – U.S. \$20.61 per barrel).

Revenues in 2000 will again be impacted by drilling success and production volumes as well as external factors such as the market for natural gas sales, the exchange rate of the Canadian dollar relative to the U.S. dollar and the WTI price for crude oil. Paramount has access to U.S. priced gas sales through aggregator contracts and direct sales and is well positioned to benefit from price increases attributable to increased pipeline takeaway capacity. At year end 1999, Paramount did not have any commodity hedges in place, anticipating a continued positive trend in natural gas prices.

ROYALTIES

Royalties (\$ thousands)	1999	1998	1997
Crown royalties	\$ 35,274	\$ 19,751	\$ 16,915
Other royalties	3,670	2,510	1,835
Subtotal	38,944	22,261	18,750
Alberta Royalty Tax Credit	(1,377)	(1,387)	(1,210)
Net royalties	\$ 37,567	\$ 20,874	\$ 17,540
Average corporate royalty rate	17.75%	12.61%	13.65%

Royalties are paid by Paramount to the owners of mineral rights with whom the Company holds leases. Paramount has mineral leases with the Crown (Provincial Governments), freeholders and other operators with whom the Company has joint interests.

During 1999, royalties net of Alberta Royalty Tax Credit ("ARTC") increased to \$37.6 million from \$20.9 million in 1998 (1997 – \$17.5 million) due to higher natural gas production and prices. As a percentage of production revenue, Paramount's corporate royalty rate was 17.75 percent as compared to 12.61 percent in 1998 (1997 – 13.65 percent).

In 1994, the Alberta Government introduced a simplified natural gas royalty system which allowed producers the option of selecting a corporate average price or government-designated reference price as the basis upon which Crown royalties would be levied. Paramount initially selected the corporate average price method, but effective January 1, 1998, switched to the Alberta-designated reference price.

For 2000, Paramount's average corporate royalty rate is expected to remain at current levels as price-sensitive royalty rates are offset by minimal royalties, subject to a payout account, from production in the Northwest Territories.

OPERATING EXPENSES

Operating Expenses (\$ thousands)	1999	1998	1997
Operating expenses	\$ 39,030	\$ 33,005	\$ 22,213
Net operating expenses per Mcfeq	\$ 0.45	\$ 0.40	\$ 0.37

Paramount's 1999 operating expenses increased 18 percent to \$39.0 million from \$33.0 million (1997 – \$22.2 million). On a unit of production basis, average operating costs increased 12 percent to \$0.45/Mcfeq from \$0.40/Mcfeq in 1998 (1997 – \$0.37/Mcfeq).

The increase can be specifically attributed to a shift in the Company's production profile from the traditional shallow gas areas. As production declines in maturing areas with a large component of fixed costs are combined with higher costs associated with operating wells and facilities in remote areas, operating costs trend upward. As further production increases are achieved in many of the newer areas, it is expected that costs on a unit-of-production basis will decline.

For 2000, average operating costs on a unit-of-production basis are expected to decrease as production volumes increase and processing capacity is optimized.

GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses (\$ thousands)	1999	1998	1997
Gross general and administrative expenses	\$ 15,771	\$ 13,471	\$ 11,522
Operating recoveries	(8,927)	(9,506)	(7,408)
General and administrative expenses before SARP	6,844	3,965	4,114
Share Appreciation Rights Plan ("SARP")	1,722	487	5,291
Net general and administrative expenses	\$ 8,566	\$ 4,452	\$ 9,405
Net general and administrative expenses per Mcfeq	\$ 0.10	\$ 0.05	\$ 0.15

General and administrative expenses, net of recoveries and before costs associated with the share appreciation rights plan, increased to \$6.8 million in 1999 as compared to \$4.0 million in 1998 (1997 – \$4.1 million). This increase is primarily due to increased staffing levels required to manage our increasing asset base and costs associated with the conversion to new financial and production accounting systems. Paramount does not capitalize any general and administrative expenses.

The share appreciation rights plan was introduced in 1994, replacing employee share options as an incentive plan for key employees. Under this plan, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and market price of the Company stock, which difference is charged to general and administrative expenses. During 1999, 150,250 rights were exercised for consideration of \$1.7 million as compared to \$0.5 million in 1998 (1997 – \$5.3 million).

General and administrative expenses before cost associated with the share appreciation rights plan are expected to increase marginally year over year while staff levels keep pace with increased activity levels and the Company completes its corporate head office move scheduled for May 2000 giving effect to Paramount's growth and activity level. Costs on a unit of production basis, however, are expected to decrease as the additional costs are offset by higher production volumes.

INTEREST EXPENSE

Interest Expense (\$ thousands)	1999	1998	1997
Interest expense	\$ 15,042	\$ 12,745	\$ 6,698
Bank loans, December 31	\$ 267,360	\$ 224,476	\$ 139,518
Debt to cash flow	2.53	2.55	1.97

Interest expense, representing interest on bank debt, increased to \$15.0 million from \$12.7 million in 1998 (1997 – \$6.7 million). The increase reflects higher average debt levels throughout the year, a direct result of the Company's exploration and development capital expenditure program which totalled approximately \$139.9 million. The Company's credit facility bears interest at the bank's prime lending rate which during 1999 averaged approximately 6.42 percent, compared to 6.83 percent in 1998 (1997 – 5.37 percent). The Company does not capitalize any interest expense.

To control the risk associated with interest rate exposure, the Company has in place an interest rate swap arrangement which has the effect of fixing the amount of interest charged on Canadian \$30.5 million of bank debt at an all in rate of 8.42 percent to August 11, 2000. The Company will continue to monitor the economic climate and fix interest rates on a portion of debt if necessary.

DRY HOLE COSTS

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred.

During 1999 dry hole costs totalled \$10.4 million as compared to \$11.7 million in 1998 and \$7.4 million in 1997. Dry hole costs include adjustments for wells drilled in previous years which have been determined to be uneconomic.

DEPLETION AND DEPRECIATION

The current year provision for depletion and depreciation expense totalled \$47.0 million as compared to \$46.6 million in 1998 (1997 – \$33.1 million). On a unit of production basis, depletion and depreciation costs averaged \$0.54/Mcfeq as compared to \$0.57/Mcfeq in 1998 (1997 – \$0.55/Mcfeq).

Included in the provision is the amortization of deferred foreign exchange losses related to the U.S. \$20 million Libor loan which in 1999 totalled \$0.7 million (1998 – \$1.6 million; 1997 – \$0.5 million). The losses result from a weak Canadian dollar relative to the exchange rate in effect at the time of the U.S. dollar financing. At December 31, 1999, the deferred foreign exchange loss was fully amortized.

For 2000, the provision for depletion and depreciation is expected to increase as a function of continued growth in production volumes. Increases or decreases in the depletion rate on a unit-of-production basis will be influenced by the reserves added through the 2000 drilling program or by acquisition.

PROVISION FOR FUTURE SITE RESTORATION AND ABANDONMENT COSTS

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 1999 the provision totalled \$1.2 million as compared to \$0.9 million in 1998 (1997 – \$0.7 million).

INCOME TAXES

In 1999, Paramount recorded current income tax expense, comprised of the Large Corporations Tax and Saskatchewan Capital Tax, in the amount of \$1.6 million as compared to \$2.1 million in 1998 (1997 – \$1.2 million).

The provision for deferred income taxes increased to \$18.4 million from \$9.0 million in 1998 (1997 – \$17.0 million). At December 31, 1999, the Company had approximately \$17.5 million of unamortized costs which are not deductible for income tax purposes (1998 – \$2.0 million). This amount is being amortized at the Company's annual depletion rate.

Estimated Income Tax Pools (\$ thousands)	December 31, 1999
Undepreciated Capital Costs	\$ 152,000
Canadian Oil and Gas Property Expenses	164,000
Canadian Exploration Expenses	66,400
Canadian Development Expenses	78,700
Foreign Exploration and Development Expenses	47,000
Other	1,700
Total Estimated Income Tax Pools	\$ 509,800

Paramount has available approximately \$509.8 million of unutilized tax pools at December 31, 1999. These tax pools, in addition to tax pools generated as a result of the Company's 2000 capital expenditure program, will be available for deduction in 2000 in accordance with Canadian income tax regulations at varying rates of amortization. Based on these tax pools and Paramount's most recent forecast of 2000 financial results and level of capital reinvestment, the Company is not expected to pay current income taxes in 2000.

CASH FLOW AND EARNINGS

(\$ thousands)	1999	1998	1997
Cash flow from operations A	\$ 105,830	\$ 88,157	\$ 70,911
Net earnings B	\$ 28,683	\$ 18,210	\$ 23,389
Weighted average shareholders' equity	\$ 295,962	\$ 233,300	\$ 162,250
After-tax rate of return	9.7	7.8	14.4

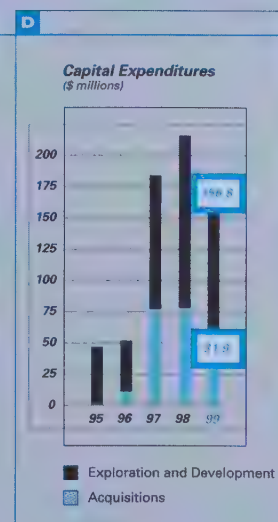
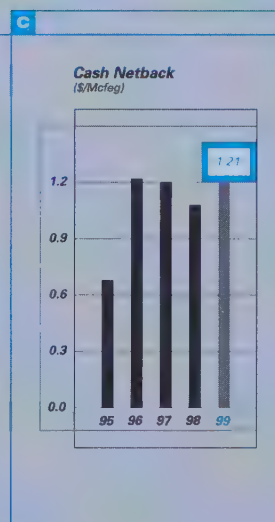
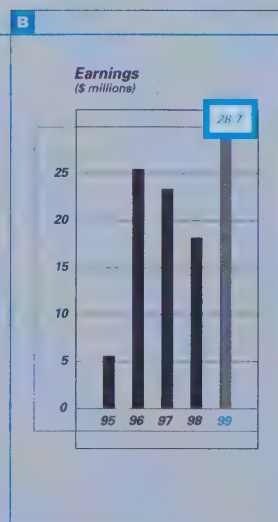
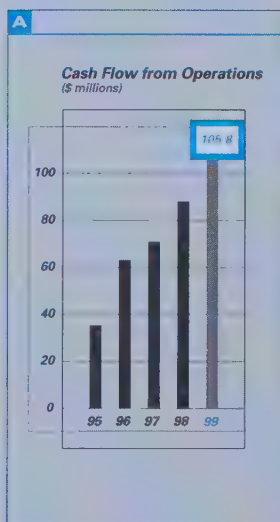
Paramount's cash flow from operations increased 20 percent to \$105.8 million or \$1.84 per common share from \$88.1 million or \$1.62 per common share in 1998 (1997 – \$70.9 million or \$1.42 per common share). **A** The weighted average shares outstanding totalled 57.5 million in 1999 compared to 54.3 million in 1998 (1997 – 49.8 million).

Earnings increased 58 percent to \$28.7 million or \$0.50 per common share compared to \$18.2 million or \$0.34 per common share in 1998 (1997 – \$23.4 million or \$0.47 per common share). **B**

Paramount's three-year average after-tax rate of return on a book basis, based upon the weighted average shareholders' equity invested was 10.2 percent.

NETBACKS

Netbacks (\$/Mcfeg)	1999	1998	1997
Revenue	\$ 2.43	\$ 2.03	\$ 2.20
Royalties (net of ARTC)	0.43	0.26	0.30
Operating costs	0.45	0.40	0.37
Operating netback	1.55	1.37	1.53
General and administrative	0.10	0.05	0.16
Lease rentals	0.05	0.05	0.04
Interest on long-term debt	0.17	0.16	0.11
Large Corporation and other taxes	0.02	0.03	0.02
Cash netback C	\$ 1.21	\$ 1.08	\$ 1.20



CAPITAL EXPENDITURES

Capital Expenditures (\$ thousands) 	1999	1998	1997
Land	\$ 27,708	\$ 8,449	\$ 9,500
Geological and geophysical	2,418	5,119	1,952
Exploration and development drilling	73,242	98,139	50,048
Production equipment and facilities	36,508	42,212	67,400
Total exploration and development expenditures	139,876	153,919	128,900
Tax effect of renounced exploration and development expenditures	(14,323)	—	—
Property acquisitions	31,924	78,063	77,000
Property dispositions	(1,894)	(19,042)	(22,600)
Other	1,173	3,042	900
Total Capital Expenditures	\$ 156,756	\$ 215,982	\$ 184,200

During 1999, expenditures for exploration and development activities totalled \$139.9 million as compared to \$153.9 million in 1998 (1997 – \$128.9 million). A total of 114 gross (86.1 net) wells were drilled during the year, compared to 172 gross (103.9 net) wells in 1998.

Total capital expenditures, including property acquisitions net of dispositions and the tax effect of flow through expenditures renounced, amounted to \$156.8 million in 1999 as compared to \$216.0 million in 1998 (1997 – \$184.2 million). The capital expenditure program was financed by internally generated cash flow of \$105.8 million and additional bank borrowings.

In October 1999, Paramount issued 2.5 million common shares from treasury pursuant to a flow-through share private placement offering at an average price of \$21.87 per share for gross proceeds of \$54.7 million. Proceeds from the financing will assist the Company in its 2000 capital expenditure program which is heavily weighted to the first quarter.

For 2000, Paramount's capital expenditure budget of \$175 million will be funded by internally generated cash flow. Any deficiency will draw upon existing credit facilities.

INVESTMENT IN DRILLING COMPANY

Paramount owns a 50 percent interest in a private company established to operate drilling rigs in Western Canada.

The Company accounts for its interest using proportionate consolidation whereby its prorata share of the financial results are combined on a line-by-line basis with similar items in the Company's financial statements.

The drilling rig became operational during the first quarter of 1998.

DEFERRED REVENUE

During 1999 Paramount recognized in revenue \$1.3 million (1998 – \$1.1 million; 1997 – \$1.2 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to shelter the Company from declining gas prices. Paramount's accounting policy recognizes these gains in the accounting years of related production. The amounts of deferred hedging gains that will be recognized in revenue by the Company in future years are as follows:

Deferred Revenue (\$ thousands)	Amount
2000	\$ 1,235
2001	1,160
2002	1,032
2003	395
Total Deferred Revenue	\$ 3,822

BANK DEBT, LIQUIDITY AND RISK MANAGEMENT

Paramount's debt and equity capital structure at December 31, 1999, was as follows: **A**

(\$ thousands, except per share)	AT COST			AT MARKET ⁽¹⁾		
	Amount	%	\$/Share ⁽²⁾	Amount	%	\$/Share ⁽²⁾
Bank debt, net of working capital	\$ 252,382	47	4.25	\$ 252,382	18.8	4.24
Deferred taxes	82,008	15	1.38	82,008	6.1	1.38
Common share equity	199,320	38	3.35	1,010,711	75.1	17.00
Total	\$ 533,710	100	8.98	\$ 1,345,101	100.0	22.62

⁽¹⁾ Close at December 31, 1999 – \$17.00/share.

⁽²⁾ At December 31, 1999 – 59,453,600 common shares.

The Company has an Extendible Revolving Term Credit Facility ("Credit Facility") with a Canadian chartered bank in the amount of \$300 million including a \$25 million working capital facility and a \$275 million production facility. Available borrowings are limited by a borrowing base, established annually based on the value of petroleum and natural gas assets as determined by the lender. The loan is reviewed annually and may be converted to a term loan repayable over five years in equal semi-annual installments. At December 31, 1999, \$267.4 million was drawn under this facility.

Working capital liquidity is maintained by drawing from and repaying the unutilized credit facilities as needed. At December 31, 1999, Paramount had working capital of \$16.4 million.

A key component of Paramount's capitalization is debt funding. Properly managed, debt funding enhances growth and profitability to shareholders without dilution or unnecessary risk. Historically, Paramount has utilized bank debt primarily for new plant development capital expenditures. As a result, the Company has maintained a weighted average net debt to cash flow ratio less than 2:1 over the past five years. **B** The Company plans to continue utilizing debt financing and believes that a net debt to cash flow ratio of 2:1 is prudent in conjunction with other risk management strategies employed. As at December 31, 1999, approximately \$30.5 million, or 12 percent of the \$252.4 million net debt outstanding, was subject to fixed interest rate agreements. The remaining debt was subject to floating interest rates applicable to financial instruments known as bankers' acceptances that generally provide for a lower rate of interest than the alternative bank prime rate cost of borrowing.

Also of significant importance to the Company is the U.S.\$/Cdn.\$ exchange ratio since 75 percent of the natural gas sales and crude oil sales of the Company are made into and priced effectively on U.S. markets. Any improvement in the Canadian dollar relative to its U.S. counterpart will have an impact on the wellhead price received for our production. To manage this risk, Paramount has entered into currency swap agreements that have fixed the exchange rates on U.S. \$66.4 million of future production revenue over the five years at Cdn. \$94.9 million. In addition the Company has a U.S. \$20 million bank loan and, as such, this is also designated as a currency hedge.

Paramount's 2000 capital expenditure program will be financed with internally generated cash flow, minor property dispositions, and where necessary, additional bank borrowings.

At December 31, 1999, the Company's issued share capital consisted of 59,453,600 common shares.

RISKS AND UNCERTAINTIES

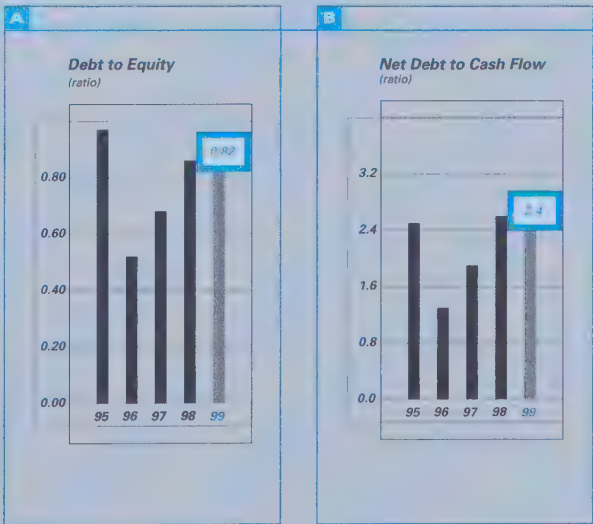
Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts as well as spot markets in its natural gas pricing strategy.

Oil prices are influenced by global supply and demand conditions as well as world wide political events. As the price of oil in Canada is based on a U.S. benchmark price, variations in the Canada/U.S. exchange rate further affect Paramount's oil price.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount controls as much of its marketing and transportation activities as possible in order to minimize any negative impact of these external factors.



The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company minimizes these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount will ensure continued compliance with environmental legislation.

Paramount is of the view that inflation will not be a significant factor in its 2000 business environment.

KYOTO PROTOCOL ON GREENHOUSE GAS EMISSIONS

Canada is signatory to an International Treaty to achieve a 6 percent reduction from 1990 greenhouse gas emission levels by 2008 – 2012, which represents approximately a 25 percent cut from current levels. At this time the Company does not know what final course of action the Canadian or United States governments will take in this regard and accordingly cannot measure the potential risk to our business.

AEUB DECISION 2000-22 – BITUMEN/NATURAL GAS CO-PRODUCTION

On April 3, the AEUB delivered its decision on the application of Gulf Canada Resources Ltd. to shut in natural gas wells in the Surmont Area on the premise that continued gas production would adversely affect the recovery of heavy oil within the McMurray formation. As a result of the decision, Paramount has been ordered to shut in Wabiskaw-McMurray production from 65 wells which it operates in the affected area.

This will result, effective May 1, 2000, with the shut in of approximately 20 MMcf/d of natural gas production from leases lawfully purchased from the Province of Alberta and diligently developed over the past 20 years in full compliance with the rights granted by the Province.

The Board notes in its decision that the Oil and Gas Conservation Act of Alberta provides that the Lieutenant Governor in Council may direct the Board to proceed to prepare a scheme to compensate persons who are injured or suffer a loss by reason of any order made by the Board pursuant to the Act.

Paramount intends to use its full right under the law to re-establish production as soon as possible and will seek full compensation for any loss which it may suffer as a result of this Board order.

2000 CASH FLOW FORECAST AND SENSITIVITY ANALYSIS

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors which are beyond the control of the Company. The following analysis assesses the magnitude of these sensitivities on the Company's 2000 cash flow using the following base assumptions.

- a) 2000 Production
 - Natural gas 260 MMcf/d
 - Crude oil/liquids 2,500 Bbl/d
- b) 2000 Average Prices
 - Natural gas \$ 2.95/Mcf
 - Crude oil/liquids (W.T.I.) \$ 23.00/Bbl
- c) Cash Flow (after tax) \$ 175 million
- d) 2000 Capital Budget
(net of disposition proceeds) \$ 175 million

The estimated pre-tax impact on cash flow is summarized in the following table.

Sensitivity (\$ millions)	Cash Flow
Gas sales change of 10 MMcf/d	\$ 7.5
Gas price change of \$0.10/Mcf	\$ 9.5
Oil and liquids sales of 100 Bbl/d	\$ 0.7
Oil and liquids price change of \$1.00/Bbl	\$ 0.7
Sensitivity to foreign exchange change \$0.01 Cdn.	\$ 1.0
Interest rates change 1%	\$ 2.6

The accompanying consolidated financial statements of Paramount Resources Ltd. and all the information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains systems of internal accounting and administrative controls of high quality, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are appropriately accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors is comprised of non-management directors. The Committee meets periodically with management as well as the external auditors to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibility, and to review the Annual Report. The Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee and Management.



Clayton H. Riddell
President and Chairman of the Board



David J. Broshko, C.A.
Chief Financial Officer

March 24, 2000

auditors' report

To the Shareholders of Paramount Resources Ltd.

We have audited the consolidated balance sheets of Paramount Resources Ltd. as at December 31, 1999 and 1998, and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1999 and 1998, and the results of its operations and cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.



Chartered Accountants

March 24, 2000
Calgary, Canada

consolidated balance sheets

as at December 31 (thousands of dollars)

1999

1998

ASSETS

Current Assets

Cash	\$ 13	\$ 81
Accounts receivable	43,109	44,580
Inventory (note 2)	16,555	10,301
Prepaid expenses	8,698	5,055

68,375 60,017

Petroleum and natural gas properties (note 3)

672,079 561,549

Deferred foreign exchange loss

- 2,629

\$ 740,454 \$ 624,195

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities

Accounts payable and accrued liabilities \$ 51,938 \$ 62,363

Bank loan (note 5)

267,360 224,476

Other indebtedness (note 4)

1,459 1,963

Provision for future site restoration and abandonment costs

4,875 3,675

Deferred revenue

3,822 5,166

Deferred income taxes

82,008 63,620

411,462 361,263

Commitment and Contingency (notes 4 and 10)

Shareholders' Equity

Share capital (note 6)

Issued and outstanding

59,453,600 common shares (1998 - 56,953,600 common shares) 199,320 158,970

Retained earnings 129,672 103,962

328,992 262,932

\$ 740,454 \$ 624,195

See accompanying notes.

On behalf of the board



C. H. Riddell
Director



G.B. Padley
Director

consolidated statements of earnings and retained earnings*as at December 31 (thousands of dollars except for per share amounts)***1999****1998****REVENUE**

Petroleum and natural gas sales

\$ 211,658**\$ 165,527**

Royalties

(38,944)**(22,261)**

Alberta Royalty Tax Credit

1,377**1,387****174,091****144,653****EXPENSES**

Operating

39,030**33,005**

Interest on long-term debt

15,042**12,745**

General and administrative

8,566**4,452**

Lease rentals

4,056**4,185**

Dry hole costs

10,399**11,667**

Geological and geophysical costs

2,418**5,119**

Gain on sales of property and equipment

(2,283)**(3,216)**

Provision for future site restoration and abandonment costs

1,200**910**

Depletion and depreciation

47,013**46,554****125,441****115,421****Income before taxes****48,650****29,232****Income and other taxes (note 7)**

Income taxes – Large Corporations Tax and other

1,567**2,109**

– deferred

18,400**8,913****19,967****11,022****Net earnings****28,683****18,210**

Retained earnings, beginning of year

103,962**88,600**

Dividends paid

(2,973)**(2,848)****Retained earnings, end of year****\$ 129,672****\$ 103,962****Net earnings per share****\$ 0.50****\$ 0.34****Weighted average shares outstanding (thousands)****57,529****54,348***See accompanying notes.*

consolidated statements of cash flows

years ended December 31 (thousands of dollars, except per share amounts)

OPERATING ACTIVITIES

Net earnings	\$ 28,683	\$ 18,210
Add (deduct) non-cash items		
Depletion and depreciation	47,013	46,554
Gain on sales of property and equipment	(2,283)	(3,216)
Provision for future site restoration and abandonment costs	1,200	910
Deferred income taxes	18,400	8,913
Add items not related to operating activities		
Dry hole costs	10,399	11,667
Geological and geophysical costs	2,418	5,119

Cash flow from operations	105,830	88,157
Deferred revenue	(1,344)	(1,108)
(Increase) Decrease in deferred foreign exchange loss	1,916	(2,366)
Change in non-cash operating working capital	(24,797)	1,098
	81,605	85,781

CASH FLOW FROM FINANCING ACTIVITIES

Bank loans	42,884	84,958
Other indebtedness	(504)	1,963
Issue of common shares, net of related costs	54,673	43,804
Dividends paid	(2,973)	(2,848)
	94,080	127,877

Cash Flow Provided by Operating and Financing Activities	175,685	213,658
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CASH FLOW FROM INVESTING ACTIVITIES

Property and equipment expenditures	145,111	148,547
Petroleum and natural gas property acquisitions	30,874	78,063
Geological and geophysical costs	2,418	5,119
Proceeds on sale of property and equipment	(2,650)	(19,042)
Other	-	1,055
	175,753	213,742

Decrease in cash	(68)	(84)
Cash, Beginning of Year	81	165
Cash, End of Year	\$ 13	\$ 81

Cash flow from operations per share	\$ 1.84	\$ 1.62
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Weighted average number of shares outstanding (thousands)	57,529	54,348
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See accompanying notes.

notes to the consolidated financial statements

(all tabular amounts expressed in thousands of dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. (the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada.

(a) Principles of Consolidation

The consolidated financial statements include the accounts of Paramount Resources Ltd., its wholly owned subsidiaries and its proportionate share of the accounts of its 50 percent interest in a private drilling company.

(b) Investment in Drilling Company

The Company has a 50 percent interest in a drilling company jointly controlled with another party. The Company accounts for its interest using proportionate consolidation whereby its prorata share of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company financial statements.

(c) Inventory

Inventory of materials and equipment is carried at the lower of cost, on a first-in first-out basis, and net realizable value.

Natural gas in storage is carried at the lower of cost and net realizable value. Cost includes all amounts incurred to produce or purchase the related gas, transportation to the storage facility and the cost of storage.

(d) Petroleum and Natural Gas Properties

The Company follows the Successful Efforts Method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net cost of unproductive wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of properties and equipment.

Depletion and depreciation of petroleum and natural gas properties including well development expenditures, production equipment, gas plants and gathering systems are provided on the unit-of-production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of other equipment is provided on a declining balance method at rates varying from 20 to 30 percent.

The net amount at which petroleum and natural gas costs on a property or project are carried is subject to a cost recovery test. The carrying values of capital assets, including the cost of acquiring proven and probable reserves, are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors. Future events could result in material changes to the carrying values recognized in the financial statements.

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

(e) Future Site Restoration and Abandonment Costs

Estimated future site restoration and abandonment costs are accrued in the financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon regulations and economic circumstances at year end.

(f) Foreign Currency Translation

Monetary assets and liabilities denominated in U.S. dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective

notes to the consolidated financial statements

(all tabular amounts expressed in thousands of dollars)

transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred except for unrealized gains or losses on translation of long-term bank loans which are deferred and amortized on a straight-line basis over the expected minimum repayment period.

(g) Financial Instruments

The Company utilizes financial instruments to manage its exposure to interest rates, foreign currency exchange rates and commodity prices. Gains or losses from foreign exchange and commodity hedge contracts are recognized in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred.

(h) Flow-Through Shares

The Company has financed a portion of its petroleum and natural gas exploration activities with a flow-through share issue. Under this type of financing arrangement, shares are issued at a fixed price and the proceeds used to fund exploration and development activities within a defined time period. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. Petroleum and natural gas properties and share capital are reduced by the estimated cost of the renounced tax deductions when the expenditures are renounced.

(i) Income Taxes

The Company follows the deferral method of tax accounting under which the income tax provision is based on the income reported in the accounts. Under this method, the Company makes full provision for income taxes deferred principally as a result of claiming capital cost allowance and exploration and development costs in excess of depletion and depreciation provided in the accounts.

2. INVENTORY

Inventory consists of the following:

	1999	1998
Materials and equipment	\$ 9,771	\$ 5,436
Natural gas in storage	6,784	4,865
	\$ 16,555	\$ 10,301

3. PETROLEUM AND NATURAL GAS PROPERTIES

	1999		1998	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Petroleum and natural gas properties	\$ 584,177	\$ 95,242	\$ 472,609	\$ 75,986
Gas plants, gathering systems and production equipment	305,668	126,831	261,653	100,194
Other	8,091	3,784	6,918	3,451
	\$ 897,936	\$ 225,857	\$ 741,180	\$ 179,631
Net book value	\$ 672,079		\$ 561,549	

Capital costs associated with non-producing petroleum and natural gas properties totalling approximately \$403 million (1998 - \$252 million) are excluded from capitalized costs subject to depletion.

notes to the consolidated financial statements

(all tabular amounts expressed in thousands of dollars)

4. INVESTMENT IN DRILLING COMPANY

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of a private drilling company as follows:

Assets		
Current assets	\$ 1	
Property and equipment	2,142	
	\$ 2,143	
Liabilities and Equity		
Current liabilities	\$ 411	
Bank loan	1,459	
Equity	273	
	\$ 2,143	

The drilling company had a reducing term loan facility available to a maximum of \$3.1 million at December 31, 1999. The loan is repayable in equal semi-annual installments of \$500,000 to June 2002. As at December 31, 1999, this facility had an effective interest rate of 6.5 percent. Paramount has provided a guarantee as security for the loan. Earnings attributed to drilling services provided to Paramount have been eliminated from the accompanying financial statements with an offsetting amount credited to petroleum and natural gas properties.

5. BANK LOAN

The Company has an Extendible Revolving Term Credit Facility ("Credit Facility") with a syndicate of Canadian chartered banks in the amount of \$300 million including a \$25 million working capital facility and a \$275 million production facility. Available borrowings are limited by a borrowing base, established annually based on the value of petroleum and natural gas assets as determined by the lenders. The borrowing base as at January 2000 was \$300 million.

The Credit Facility is reviewed annually by June 30 of each year and may be converted to a term loan repayable over five years in equal semi-annual installments. The Bank has indicated that, while it reserves the right to request payment on demand, no principal payments are anticipated. Accordingly, the bank loan has been classified as long term.

As at December 31 the following amounts were drawn under this facility.

	1999	1998
Bankers' acceptances		
– 30 days at an average rate 5.91% (1998 – 6.1 %)	\$ 207,800	\$ 163,000
Bankers' acceptances	30,500	30,500
LIBOR advances (U.S. \$20,000,000)	29,060	30,976
	\$ 267,360	\$ 224,476

The Company has provided a first floating charge on all assets in the amount of \$500 million and a general assignment pursuant to a general security agreement.

The Company has an interest rate exchange agreement fixing the interest rate on \$30.5 million of long term debt at 8.4 percent to August 11, 2000.

The Company has letters of credit totalling \$4.8 million outstanding with a Canadian Chartered Bank.

notes to the consolidated financial statements

(all tabular amounts expressed in thousands of dollars)

6. SHARE CAPITAL

Authorized Capital

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

Issued Capital		
Common Shares	Number	Consideration
Balance December 31, 1997	53,953,600	\$ 115,166
Issuance of common shares for cash	3,000,000	45,000
Share issue costs (net of deferred tax reduction of)	(963,750)	(1,196)
Balance December 31, 1998	56,953,600	158,970
Issuance of common shares for cash	2,500,000	54,687
Tax benefits relating to qualifying expenditures renounced to flow-through shareholders		(14,323)
Share issue costs (net of deferred tax reduction of)	(11,456)	(14)
Balance December 31, 1999	59,453,600	\$ 199,320

Share Appreciation Rights Plan

As at December 31, 1999, 2.4 million Share Appreciation Rights were reserved under the Company's Share Appreciation Rights Plan, of which rights to purchase 1.1 million are outstanding, exercisable to January 31, 2003, at prices ranging from \$6.46 to \$16.50 per share. During 1999, 150,250 rights were exercised for consideration of \$1.7 million (1998 – \$0.5 million) which amount is recorded to general and administrative expenses. Under the Share Appreciation Rights Plan, no compensation expense is recognized when share appreciation rights are granted to employees. Any consideration paid to employees on exercise of share appreciation rights is charged to general and administrative expense.

7. INCOME TAXES

Petroleum and natural gas interests include approximately \$17.5 million (1998 – \$2.0 million) of unamortized costs which are not deductible for income tax purposes by the Company.

The income tax provision for the years ended December 31, 1999 and 1998, differs from the income taxes obtained by applying the Canadian corporate tax rate to income before taxes as follows:

	1999	1998
Corporate tax rate	44.62%	44.62%
Calculated income tax expense	\$ 21,708	\$ 13,043
Increase (decrease) resulting from:		
Non-deductible Crown charges,		
net of Alberta Royalty Tax Credit	16,275	9,851
Federal resource allowance	(20,347)	(12,934)
Non-deductible depletion	1,063	(1,760)
Large Corporation Capital Tax and other	1,567	2,109
Other	(299)	713
Income tax provision	\$ 19,967	\$ 11,022

notes to the consolidated financial statements*(all tabular amounts expressed in thousands of dollars)***8. FINANCIAL INSTRUMENTS**

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of U.S. \$66.4 million for Cdn. \$94.9 million over the next five years at Cdn. \$1.4286. The Canadian dollar/U.S. dollar closing exchange rate was \$1.4530 as at December 31, 1999 (1998 – \$1.5488).

	U.S. \$ Amount	Weighted Average Exchange Rate
2000	\$ 20,580	1.4285
2001	20,340	1.4297
2002	20,520	1.4296
2003	4,570	1.4211
2004	360	1.4206
Totals	\$ 66,370	1.4286

During 1999, \$1.3 million of net gains related to hedging contracts (1998 – \$0.1 million net losses) are included in natural gas sales revenue.

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based; thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices.

The fair values of other financial instruments, including cash, accounts receivable, and accounts payable and accrued liabilities, approximate their carrying values.

9. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. Although the change in date has occurred, it is not possible to conclude that all aspects of the Year 2000 Issue that may affect the entity, including those related to customers, suppliers, or other third parties, have been fully resolved.

10. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current financial statement presentation. These consolidated financial statements adopt, on a retroactive basis, the requirements of the Canadian Institute of Chartered Accountants relating to the presentation of the Cash Flow Statement.

INCORPORATION

Paramount Resources Ltd. ("Paramount" or the "Company") was incorporated under the laws of the Province of Alberta on February 14, 1978. The Company commenced operations as a public company listed on the Alberta Stock Exchange on December 18, 1978, with a successful Initial Public Offering that raised \$4.7 million and a share exchange with a private company, Paramount Oil & Gas Ltd., for certain crude oil and natural gas assets with book value of \$341,000.

On November 30, 1984, Paramount was listed on The Toronto Stock Exchange (TSE). Paramount was added to the TSE 300 Composite Index (Subgroup 3.2 Oil & Gas Producers) and the TSE 200 Index, effective January 16, 1998.

The head and principal office of the Company is located at Suite 4000 First Canadian Centre, 350 Seventh Avenue S.W., Calgary, Alberta, T2P 3W5. Effective May 19, 2000, Paramount's head and principal office will be located at Suite 4700 Bankers Hall West, 888 Third Street S.W., Calgary, Alberta T2P 5C5.

MANAGEMENT OF THE COMPANY

The management of the Company is provided by six officers, one of whom currently also serves as a director. There are eight non-management directors to complete the Board of Directors. The names, municipality of residence, position with Paramount and principal occupation of each of the officers and directors can be found in the Management Information and Proxy Circular dated March 30, 2000.

The term of office for each director of the Company is from the date of the annual meeting at which he is elected or appointed until the annual meeting next following or until his successor is elected or appointed. The current Board of Directors was nominated and elected at the Annual Meeting of the Shareholders held on May 20, 1999. The Board of Directors has an Audit Committee which consists of Messrs. Padley, Roy and MacInnes; a Compensation Committee which consists of Messrs. Riddell, Roy and Wylie; and an Environmental Committee which consists of Messrs. MacInnes, Roy and Wylie.

As at December 31, 1999, the directors and officers of the Company as a group beneficially owned 32,393,276 common shares, representing 54.48 percent of the 59,453,600 issued and outstanding common shares of Paramount Resources Ltd.

The 2000 Annual General Meeting will be held on June 8 in Calgary, Alberta.

DESCRIPTION AND DEVELOPMENT OF BUSINESS

Paramount Resources Ltd. is a Canadian natural resource company involved in the exploration, development and production of petroleum and natural gas, primarily in Alberta but also in British Columbia, Saskatchewan, the Northwest Territories, Wyoming and California. Exploration efforts have historically been concentrated on shallow gas prospects in northeastern Alberta. In 1999, sales of natural gas accounted for 92 percent of the Company's total production.

The Company's ongoing exploration, development and production activities are designed to establish new reserves of oil and natural gas and maintain as well as increase the productive capacity of existing fields. In order to optimize its net capacity and control costs, the Company strives to: increase ownership and throughput in existing plants as economic opportunities arise; occasionally dispose of lower working interest properties; maintain a high working interest in low to medium risk projects; and enter into joint venture arrangements on select high risk/high return exploration prospects.

Paramount also participates in the petroleum and natural gas industry through acquisition of petroleum and natural gas assets. The Company's acquisition strategy focuses on long-term asset value including assets which will increase Paramount's current working interest. To take advantage of opportunities as they arise, the Company maintains a strong balance sheet which allows such acquisitions to be financed.

At December 31, 1999, approximately 77 percent of Paramount's proven and probable natural gas reserves were located in Alberta with the balance in British Columbia, Northwest Territories and Saskatchewan. Oil and natural gas liquids reserves are 46 percent located in Alberta, with the remainder in Saskatchewan, British Columbia and the Northwest Territories. In 1999, Paramount operated 84 percent of its natural gas production and approximately 43 percent of its crude oil and liquids production.

In addition to the historical focus on shallow gas in northeastern Alberta, Paramount is continuing to actively explore for petroleum and natural gas reserves in Central and Northwest Alberta, British Columbia, southeastern Saskatchewan, Northwest Territories, California and Wyoming. Efforts are progressing in the Northwest Territories where a 52-kilometer gathering system was constructed in the first quarter of 2000 to bring our first Northwest Territories production onstream. The development of new core areas ensures adequate supply for existing gas markets and contracts, and is accelerated when markets are sufficient to support additional supply.

CAPITAL TRANSACTIONS

Since inception, the Company has raised share capital in public markets on four occasions. In addition, the shares of Paramount have split twice on a three-for-one basis. As at December 31, 1999, the Company had 59,453,600 shares outstanding with an indicated market capitalization of \$1,010.7 million based upon the \$17.00 per share closing price on the TSE. Following is a summary of capital transactions the Company has completed in the past five years.

1. On October 8, 1999, Paramount issued 2.5 million common shares at an average price of \$21.87 per share pursuant to a private placement flow-through share offering for gross proceeds of \$54.7 million. Proceeds from the issue are being used to complement the 1999/2000 capital expenditure program.
2. On November 13, 1998, Paramount issued 3.0 million common shares at a price of \$15.00 per share for gross proceeds of \$45.0 million pursuant to a prospectus dated November 4, 1998. Proceeds were initially used to reduce bank indebtedness.
3. On November 4, 1997, Paramount issued 4.0 million common shares at \$16.50 per share pursuant to a prospectus dated November 4, 1997.
4. On June 4, 1997, Paramount's common shares were split on a three-for-one basis resulting in 49,203,600 issued and outstanding common shares.

COMPETITIVE CONDITIONS

The petroleum and natural gas industry is highly competitive. Paramount competes with numerous other participants in the search for and acquisition of crude oil and natural gas properties and in the marketing of these commodities. Successful reserve replacement in the future will depend not only on the further development of present properties, but also on the ability to select and acquire suitable prospects for exploratory drilling.

Paramount has firm service for most of its natural gas production as opposed to interruptible allocations on pipeline systems. The Company closely monitors the daily production from all of its plants ensuring that contractual obligations will be met. The operational policy of producing excess gas into storage to maintain production, even when markets may not be available, ensures the reliability of the supply of natural gas during peak demand periods and reduces unit operating costs. Balancing contractual commitments, natural gas sales are directed to those markets where the Company believes prices will be best.

RECENT DEVELOPMENTS

Late in 1998, Gulf Canada Resources Ltd. re-submitted an application to the Alberta Energy and Utilities Board (AEUB) requesting that the AEUB issue an order shutting in 183 wells located on and in the vicinity of its Oil Sands holdings in the Surmont Area of northeastern Alberta. The AEUB held a public hearing on this application which ran from April through September of 1999. Paramount, as a member of the Surmont Gas Producers, was an active opponent of this application at the hearing.

On March 30, 2000, the AEUB issued *EUB Decision 2000-22* and a Board Order dated April 3, 2000 ordering the shut-in of 146 of the 183 wells and terminating the rights of natural gas leaseholders and producers to produce natural gas from the Wabiskaw and McMurray formations effective May 1, 2000. Paramount is the operator of 65 of these wells, 41 of which are currently capable of economic natural gas production from the Wabiskaw/McMurray at varying rates. The approximate average volume from these producing wells is currently 20.5 MMcf/d before deduction of the Crown royalty share and any surface losses associated with producing the gas. In addition to the Paramount-operated wells, Paramount has an interest in 10 other wells subject to the Board order. Paramount's share of production from these wells averages 1.3 MMcf/d before deduction of Crown royalties.

Paramount intends to use its full rights under the law to re-establish production as soon as possible. At the same time, Paramount, along with the other members of the Surmont Gas Producers Group, is investigating all available options for compensation. These include compensation for the loss of both production and rights associated with Crown mineral agreements.

ENVIRONMENTAL PROTECTION

Paramount has in place an Environmental Committee of the Board of Directors comprised of three non-management directors of the Company. The tenet of the Company's environmental policy is as follows:

Paramount Resources Ltd. "Paramount" is committed to protecting the environment, to maintaining public health and safety, and to compliance with all applicable environmental laws, regulations and standards. Paramount will do all that it reasonably can to ensure that sound environmental practices are followed in all of its operations and activities.

The Committee is guided by a specific set of principles to ensure that this policy is supported. These principles apply to all employees of Paramount and are designed to make certain that all applicable environmental laws, regulations and standards are complied with. The Company monitors all activities and makes reasonable efforts to ensure that companies who provide services to Paramount will operate in a manner consistent with its environmental policy.

HUMAN RESOURCES

At January 1, 2000, Paramount had 70 full time head office employees and 53 full time employees at field locations. The Company's compensation of full time employees includes a combination of salary, benefits, and participation in either a share appreciation rights plan or a company-assisted share purchase savings plan. Shares under the savings plan are purchased in the marketplace by the plan trustee.

LAND

The following table sets forth Paramount's land position at December 31, 1999. The Company's holdings total 4,373,332 gross (2,834,423 net) acres. Approximately 65 percent of the Company's gross land holdings are considered undeveloped.

(thousands of acres)	1999		1998		1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Undeveloped Land										
Alberta	1,950	1,388	1,789	1,178	1,505	920	1,175	786	1,151	704
British Columbia	191	105	138	73	99	44	64	36	48	33
Saskatchewan	199	39	238	44	438	145	100	17	2	1
Northwest Territories	494	221	509	220	309	114	240	93	123	105
Subtotal	2,834	1,753	2,674	1,515	2,351	1,223	1,579	932	1,324	843
Acreage assigned reserves										
Alberta	1,446	1,027	1,280	866	1,091	739	653	485	963	579
British Columbia	17	9	16	9	16	8	4	2	5	3
Saskatchewan	16	4	15	40	51	22	2	1	1	—
Northwest Territories	60	41	45	3	46	40	50	44	50	44
Subtotal	1,539	1,081	1,356	918	1,204	809	709	532	1,019	626
Total Acres	4,373	2,834	4,030	2,433	3,555	2,032	2,288	1,464	2,343	1,469

"Gross" acres means the total acreage in which Paramount has a working interest and "net" acres means the number of acres obtained by multiplying the gross acres by Paramount's working interest therein.

DRILLING HISTORY

The following table summarizes the results of Paramount's drilling activity for each of the last five fiscal years. The working interest in certain of these wells may change after payout.

	1999		1998		1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Gas	50	41.9	50	36.3	58	43.8	49	20.3	67	31.1
Oil	8	4.0	10	3.9	11	2.2	14	3.6	4	4.0
Standing/service	1	0.5	5	3.8	20	7.1	1	0.5	—	—
Dry	3	2.0	4	3.5	4	3.0	3	2.0	5	2.4
Subtotal	62	48.4	69	47.5	93	56.1	67	26.4	76	37.5
Exploration Wells										
Gas	42	31.3	59	38.1	23	10.1	28	15.7	34	17.0
Oil	1	0.3	13	2.9	17	3.2	3	0.9	3	2.2
Standing/service	2	0.4	6	3.6	8	2.5	2	0.5	—	—
Dry	7	5.7	25	11.8	6	1.5	7	1.5	3	2.0
Subtotal	52	37.7	103	56.4	54	17.3	40	18.6	40	21.2
Total Wells	114	86.1	172	103.9	147	73.4	107	45.0	116	58.7

"Gross" wells means the number of wells in which Paramount has a working interest, and "net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

"Exploratory" well is a well drilled either in search of a new and as yet undiscovered pool of petroleum or natural gas or with the expectation of significantly extending the limit of a pool which is partly discovered.

"Development" well is a well drilled within or in close proximity to a discovered pool of petroleum or natural gas.

OIL AND NATURAL GAS WELLS

As at December 31, 1999, Paramount had an interest in 1,627 gross (1,146.5 net) producing and non-producing oil and natural gas wells as follows:

As at December 31, 1999	Producing		Non-Producing	
	Gross	Net	Gross	Net
Crude oil wells				
Alberta	28	14.7	22	12.4
British Columbia	5	2.4	2	0.9
Saskatchewan	62	13.2	15	2.7
Northwest Territories	–	–	11	9.0
Subtotal	95	30.3	50	25.0
Natural gas wells				
Alberta	863	636.0	570	429.4
British Columbia	11	6.6	11	5.4
Saskatchewan	3	0.7	3	0.7
Northwest Territories	–	–	21	12.4
Subtotal	877	643.3	605	447.9
Total	972	673.6	655	472.9

"Non-producing" wells are wells which Paramount considers capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.

"Gross" wells means the number of wells in which Paramount has a working interest, and "net" wells means the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage working interest therein.

RESERVES

Paramount's assigned reserves of crude oil, natural gas liquids, and natural gas are located exclusively in Canada. For 1999, all reserves, except for those in the Midale area, were determined through independent engineering evaluations completed by McDaniel & Associates Consultants Ltd. ("McDaniel"), a firm of independent petroleum consultants. Their report was prepared effective January 1, 2000 and dated March 22, 2000. Reserves in the Midale area were evaluated by Gilbert Laustsen Jung Associates Ltd. of Calgary, Alberta. The Company's five-year summary of reserves is outlined in the following tables. Probable reserves reported in the tables below have been reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)	1999	1998	1997	1996	1995
Gross before royalties					
Proven producing	370.9	412.8	357.0	190.6	195.9
Proven non-producing	223.8	194.5	124.7	155.2	149.4
Total proven	594.7	607.3	481.7	345.8	345.3
Probable additional	155.1	180.9	155.1	130.6	103.0
Total proven and probable	749.8	788.2	636.8	476.4	448.3
50% reduction for risked probable reserves	(77.5)	(90.5)	(77.6)	(65.3)	(51.5)
Total risked reserves	672.3	697.7	559.2	411.1	396.8
Net after royalties					
Proven producing	284.0	318.8	283.3	147.6	149.2
Proven non-producing	192.7	173.4	111.9	134.4	128.9
Total proven	476.7	492.2	395.2	282.0	278.1
Probable additional	127.7	150.3	127.2	106.4	85.2
Total proven and probable	604.4	642.5	522.4	388.4	363.3
50% reduction for risked probable reserves	(63.8)	(75.2)	(63.6)	(53.2)	(42.6)
Total risked reserves	540.6	567.3	458.8	335.2	320.7

Crude oil & liquids reserves (MBbl)	1999	1999	1999	2000	2000
Gross before royalties					
Proven producing	3,231.1	5,018.0	4,912.0	5,089.8	2,895.6
Proven non-producing	3,032.8	2,877.0	3,474.0	484.3	199.1
Total proven	6,263.9	7,895.0	8,386.0	5,574.1	3,094.7
Probable additional	2,616.0	3,735.0	5,053.9	5,088.0	3,490.0
Total proven and probable	8,879.9	11,630.0	13,439.9	10,662.1	6,584.7
50% reduction for risked probable reserves	(1,308.0)	(1,867.5)	(2,527.0)	(2,544.0)	(1,745.0)
Total risked reserves	7,571.9	9,762.5	10,912.9	8,118.1	4,839.7
Net after royalties					
Proven producing	2,569.3	4,102.0	3,785.0	3,991.1	2,295.0
Proven non-producing	2,303.7	2,109.0	2,566.2	348.8	142.3
Total proven	4,873.0	6,211.0	6,351.2	4,339.9	2,437.3
Probable additional	2,134.6	3,053.0	3,858.5	4,022.1	2,923.5
Total proven and probable	7,007.6	9,264.0	10,209.7	8,362.0	5,360.8
50% reduction for risked probable reserves	(1,067.3)	(1,526.5)	(1,929.3)	(2,011.0)	(1,461.7)
Total risked reserves	5,940.3	7,737.5	8,280.4	6,351.0	3,899.1

RESERVE RECONCILIATION

The table below sets forth Paramount's reconciliation of gross proven and probable reserves from January 1, 1999 to January 1, 2000, using escalated prices and costs. The probable reserves have been reduced by 50 percent to account for risk.

Natural gas reserves (Bcf)	Proven	Probable	Total
Risk discounted balance at January 1, 1999	607.3	90.5	697.8
Revisions of previous estimates	(54.5)	(41.8)	(96.3)
Extensions and discoveries	83.3	16.1	99.4
Acquisitions of natural gas in place	36.4	2.4	38.8
Production estimate	(77.8)	(2.5)	(80.3)
50% reduction for risked probable reserves	-	12.9	12.9
Balance at January 1, 2000	594.7	77.6	672.3
Crude oil and liquids (MBbl)			
Risk discounted balance at January 1, 1999	7,895.0	1,867.5	9,762.5
Revisions of previous estimates	(1,289.0)	(1,136.6)	(2,425.6)
Extensions and discoveries	316.0	27.0	343.0
Acquisitions of crude oil/liquids in place	8.9	-	8.9
Production estimate	(667.0)	(9.2)	(676.2)
50% reduction for risked probable reserves	-	559.3	559.3
Balance at January 1, 2000	6,263.9	1,308.0	7,571.9

The following table sets forth Paramount's reconciliation of gross natural gas reserves for each of the past five years.

Natural gas reserves (Bcf)	1999	1998	1997	1996	1995
Opening balance	697.8	559.2	411.1	396.8	384.4
Revisions of previous estimates	(96.3)	71.0	45.2	13.9	15.5
Extensions and discoveries	99.4	100.1	31.3	56.0	42.3
Acquisitions of gas in place	38.8	64.9	150.5	76.8	15.9
Dispositions of gas in place	—	(16.9)	(19.6)	(71.9)	(12.6)
Production estimate	(80.3)	(67.7)	(47.0)	(46.7)	(48.0)
50% reduction for risked probable reserves	12.9	(12.8)	(12.3)	(13.8)	(0.7)
Closing balance	672.3	697.8	559.2	411.1	396.8

The following definitions form the basis of classification for reserves presented in the McDaniel report.

- "Proven Reserves"** are defined as those quantities of crude oil, natural gas and natural gas by-products which, upon analysis of drilling, geological and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and gas reservoirs under current technology and existing economic conditions. There is relatively little risk associated with these reserves. Proven developed reserves are subdivided into the following groups, depending on their status of development. These are proven reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

 - Proven Developed Producing Reserves**
These are proven developed reserves which are presently being produced, or if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner.
 - Proven Developed Non-Producing Reserves**
These are proven developed reserves which are currently not being produced but do exist in completed intervals from existing wells that require relatively minor capital expenditures to produce. These reserves are classified as proven developed since the cost of making such reserves available for production is relatively small compared to the cost of a new well.
- "Probable Reserves"** are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proven under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proven category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future. The risk associated with these reserves generally ranges from 25 to 75 percent.
- "Gross Reserves"** are defined as the reserves owned before deduction of any royalties.
- "Net Reserves"** are defined as the gross reserves of the properties in which an interest is held, less all royalties and interests owned by others.

The McDaniel report has relied on representations by Paramount with respect to its ownership and production which representations were accepted by McDaniel without independent verification.

MAJOR PRODUCING PROPERTIES

The following table summarizes average production volumes from Paramount's major producing properties, for each of the last five fiscal years.

Natural Gas (MMcf/d)	1999	1998	1997	1996	1995
<i>Northeast Alberta – East Side</i>					
Bohn Lake	4.8	–	–	–	–
Chard	3.5	4.2	3.6	4.8	5.5
Cold Lake	17.1	13.3	–	–	–
Corner	20.3	25.2	24.1	20.0	19.1
Kettle River	24.9	24.8	21.2	15.6	16.7
Leismer	3.5	3.1	3.7	1.5	1.9
Quigley	10.1	11.6	6.8	6.5	7.1
Thornbury	6.9	6.8	–	–	–
Winefred	7.1	6.5	–	–	–
Other	7.0	7.3	6.3	3.8	2.0
<i>Northeast Alberta – West Side</i>					
Legend	14.1	14.6	9.7	11.8	12.9
North Liege	4.6	6.3	8.3	11.0	13.7
South Liege	9.0	9.3	1.1	–	2.4
East Liege	5.7	–	–	–	–
Saleski	5.7	6.7	7.4	9.0	9.2
Teepee Creek	9.3	10.7	6.8	–	–
<i>Central Alberta</i>					
Kaybob	9.8	6.5	8.3	11.3	13.8
Kaybob North	24.5	13.2	7.3	3.3	–
Pine Creek	4.9	–	–	–	–
Zaremba	4.2	7.4	3.1	–	–
Other	4.2	–	–	–	–
<i>Northwest Alberta</i>					
Bistcho Lake	10.0	8.0	6.6	–	–
Pedigree	3.3	–	–	–	–
Other	0.7	–	–	–	–
<i>Non-Core</i>	4.8	18.0	24.3	28.5	30.7
Total	220.0	203.5	148.6	127.1	135.0
<i>Crude Oil and Liquids (Bbl/d)</i>					
Alberta	839	1,021	711	1,120	807
Saskatchewan	852	790	616	332	–
Other	163	177	65	65	–
Total	1,854	1,988	1,392	1,517	807

The following is a description of Paramount's major producing properties at December 31, 1999. Paramount's exploration efforts are primarily concentrated in Alberta, Saskatchewan, British Columbia, the Northwest Territories, and California. In past years, the majority of properties were in northeastern Alberta and produced natural gas from the shallow, high deliverability natural gas reserves whose discovery and development has been the focus of the Company's corporate strategy since its inception in 1978. Production from this traditional area accounted for 70 percent of the Company's total natural gas production. Natural gas production from the Company's core area in Central Alberta accounted for 20 percent of the total production in 1999, with 6 percent from Northwest Alberta and the remaining

4 percent is from non-operated production in non-core areas. Paramount's crude oil production is mainly from the Company's non-operated battery at Midale in Saskatchewan, and the operated production in Central Alberta from the Kaybob West facility.

Paramount's working interests have been determined before royalties and after deduction of any third party carried interests. Production refers to Paramount's working interest before the deduction of royalties. Plant capacity is determined by the maximum throughput for a given month during 1999, and has been calculated for Company operated facilities.

Northeast Alberta – East Side – Kettle

These properties are located in the Company's northeasternmost shallow gas production area. The natural gas produced from these facilities is Cretaceous in age at depths up to 450 metres.

There are three company-operated plants at Quigley, Kettle River and Chard; two non-operated plants at Winefred and Surmont, where the Company's gas is processed for a custom fee, and Bohn Lake where the Company has a working interest in a third party-operated plant. Details relative to each major property and facility are described below.

Chard	25,156 gross (21,276 net) acres of land 11 gross (8.32 net) producing wells, 12 gross (11.03 net) non-producing wells Maximum plant capacity for 1999: 6.3 MMcf/d, Average production to Paramount: 3.5 MMcf/d
Kettle River	35,200 gross (33,111) net acres of land 41 gross (39.2 net) producing wells, 14 gross (13.5 net) non-producing wells Maximum plant capacity for 1999: 25.5 MMcf/d, Average production to Paramount: 24.9 MMcf/d
Quigley	49,920 gross (49,920) net acres of land 39 gross (39.0 net) producing wells, 22 gross (21.8 net) non-producing wells Maximum plant capacity for 1999: 10.8 MMcf/d, Average production to Paramount: 10.1 MMcf/d
Winefred	96,040 gross (81,768) net acres of land 58 gross (48.2 net) producing wells, 26 gross (20.0 net) non-producing wells Average production to Paramount: 7.1 MMcf/d
Bohn Lake	45,440 gross (14,719 net) acres of land 39 gross (11.6 net) producing wells, 8 gross (2.7 net) non-producing wells Average production to Paramount: 4.8 MMcf/d

Northeast Alberta – East Side – Corner

These properties, located in the shallow gas region directly west of Kettle, produce natural gas from the high deliverability Colony, McMurray and Clearwater reservoirs found in this core area.

The Company owns and operates four facilities at Corner, Leismer, South Leismer and Clyde Lake. Paramount gas is also processed at two outside-operated facilities at Pony and Thornbury for a custom processing fee.

The major producing facilities in this area are further detailed below.

Corner	90,520 gross (90,520.0 net) acres of land 54 gross (53.4 net) producing wells, 26 gross (25.3 net) non-producing wells Maximum plant capacity for 1999: 23.0 MMcf/d, Average production to Paramount: 20.3 MMcf/d
Leismer	44,800 gross (38,016 net) acres of land 28 gross (24.0 net) producing wells, 31 gross (26.1 net) non-producing wells Maximum plant capacity for 1999: 5.6 MMcf/d, Average production to Paramount: 3.5 MMcf/d
Thornbury	52,480 gross (36,096 net) acres of land 54 gross (38.6 net) producing wells, 15 gross (10.6 net) non-producing wells Average production to Paramount: 6.9 MMcf/d

Northeast Alberta – East Side – Cold Lake

Cold Lake is located south of the aforementioned properties, still in the northeastern shallow gas region and producing from Cretaceous age clastic reservoirs. There is gas producing to two Company-owned plants in this area and four facilities that transport and produce Paramount gas for a custom processing fee.

The Company also has a 5 to 6 percent net profit interest in 159 heavy oil wells from two different projects in this area.

Cold Lake	159,200 gross (130,311 net) acres of land 124 gross (101.1 net) producing wells, 44 gross (35.7 net) non-producing wells Average production to Paramount: 17.1 MMcf/d
------------------	---

Northeast Alberta – West Side

These properties form the Company's Northeast Alberta – West Side core area. This gas is produced from carbonate reservoirs of Devonian age at depths ranging from 200 to 600 metres as well as from the Cretaceous McMurray and Wabiskaw formations.

The Company produces gas from six facilities in this area, five of which the Company owns and operates; Company-operated facilities include Legend, East Liege, North Liege, South Liege and Saleski. The Company owns 50 percent of the outside-operated plant at Teepee Creek.

These properties are described below.

Legend	180,080 gross (158,358 net) acres of land 41 gross (30.2 net) producing wells, 13 gross (10.3 net) non-producing wells Maximum plant capacity for 1999: 14.6 MMcf/d, Average production to Paramount: 14.1 MMcf/d
North Liege	69,760 gross (63,335 net) acres of land 18 gross (17.3 net) producing wells, 19 gross (16.5 net) non-producing wells Maximum plant capacity for 1999: 6.4 MMcf/d, Average production to Paramount: 4.6 MMcf/d
South Liege	107,360 gross (99,045 net) acres of land 30 gross (27.4 net) producing wells, 37 gross (34.0 net) non-producing wells Maximum plant capacity for 1999: 12.1 MMcf/d, Average production to Paramount: 9.0 MMcf/d
East Liege	78,080 gross (78,080 net) acres of land 11 gross (9.9 net) producing wells, 5 gross (4.6 net) non-producing wells Maximum plant capacity for 1999: 10.1 MMcf/d, Average production to Paramount: 5.7 MMcf/d
Saleski	88,000 gross (81,401 net) acres of land 19 gross (18.3 net) producing wells, 9 gross (8.1 net) non-producing wells Maximum plant capacity for 1999: 5.9 MMcf/d, Average production to Paramount: 5.7 MMcf/d
Teepee Creek	140,939 gross (89,270 net) acres of land 18 gross (9.0 net) producing wells, 17 gross (8.5 net) non-producing wells Average production to Paramount: 9.3 MMcf/d

Central Alberta

These properties in Central Alberta produce gas, oil and natural gas liquids from the Cretaceous Viking, Spirit River, Notikewin and Bluesky/Gething as well as the Triassic Charlie Lake, Halfway, and Montney formations.

Paramount operates one natural gas plant at Kaybob and an oil battery at West Kaybob. The Company has a working interest in the plant at Kaybob North and processes gas through third party-operated facilities at Pine Creek, Fox Creek, Kaybob South, Wild River and Zarembo in British Columbia.

The major producing facilities are described below.

Kaybob	67,680 gross (54,040 net) acres of land 24 gross (21.9 net) producing wells, 17 gross (12.8 net) non-producing wells Maximum plant capacity for 1999: 12.8 MMcf/d, Average production to Paramount: 9.8 MMcf/d, 89 Bbl/d
Kaybob West	26,540 gross (25,598 net) acres of land 1 gross (1.0 net) non-producing gas wells, 7 gross (7.0 net) producing oil wells, 2 gross (2.0 net) non-producing oil wells Average production to Paramount: 297 Bbl/d, 0.3 MMcf/d
Kaybob North	100,970 gross (63,212 net) acres of land 76 gross (49.9 net) producing gas wells, 28 gross (16.7 net) non-producing gas wells 11 gross (5.2 net) producing oil wells, 13 gross (7.7 net) non-producing oil wells Average production to Paramount: 24.5 MMcf/d, 218 Bbl/d
Pine Creek	24,640 gross (16,464 net) acres of land 22 gross (11.4 net) producing gas wells, 16 gross (6.9 net) non-producing gas wells 2 gross (0.2 net) producing oil wells Average production to Paramount: 4.9 MMcf/d, 152 Bbl/d
Zarembo, B.C.	27,622 gross (14,576 net) acres of land 11 gross (6.6 net) producing gas wells, 7 gross (3.4 net) non-producing gas wells 5 gross (2.4 net) producing oil wells, 2 gross (0.9 net) non-producing oil wells Average production to Paramount: 4.2 MMcf/d, 135 Bbl/d

Northwest Alberta

Bistcho Lake is located approximately 60 kilometres north of the Zama Lake pipeline terminal. This Company-operated sour gas processing facility produces gas of Middle Devonian age at depths up to 1,500 metres. The Company operates two plants in this area at Bistcho Lake and Sousa; gas is processed through a third party-operated plant at Pedigree for a processing fee.

The major properties are described below.

Bistcho Lake 376,510 gross (180,801 net) acres of land
24 gross (12.1 net) producing gas wells, 18 gross (8.7 net) non-producing gas wells
Maximum plant capacity for 1999: 22.0 MMcf/d, Average production to Paramount: 10.0 MMcf/d, 11 Bbl/d

Pedigree 40,960 gross (22,640 net) acres of land
3 gross (3.0 net) producing gas wells, 2 gross (2.0 net) non-producing gas wells
Average production to Paramount: 3.3 MMcf/d

Midale, Saskatchewan

The Company has an interest in 52,473 gross (6,876 net) acres in this non-operated area in southeast Saskatchewan. The area consists of 54 gross (11.6 net) oil wells producing to non-operated batteries and 11 gross (2.1 net) non-producing oil wells. Production to Paramount from this area averaged 852 Bbl/d in 1999.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING INFORMATION

a) Annual Financial Information

(\$ thousands except per share amounts) ⁽¹⁾	Year Ended December 31				
	1999	1998	1997	1996	1995
Revenues	211,658	165,527	130,460	100,977	70,428
Expenses					
Royalties, net of ARTC	37,567	20,874	17,540	7,763	7,280
Operating	39,030	33,005	22,213	16,196	14,624
Interest	15,042	12,745	6,698	6,382	7,185
General and administrative	8,566	4,452	9,405	5,972	3,642
Lease rentals	4,056	4,185	2,498	1,955	1,944
Large Corporation Tax and other	1,567	2,109	1,195	602	440
Cash flow from operations	105,830	88,157	70,911	63,107	35,313
Per share	1.84	1.62	1.42	1.32	0.74
Depreciation and depletion	47,013	46,554	33,053	23,760	24,969
Dry hole costs	10,399	11,667	7,378	2,565	2,150
Net earnings	28,683	18,210	23,389	25,462	5,622
Per share	0.50	0.34	0.47	0.53	0.12
Balance Sheet Information					
Capital expenditures	156,756	215,982	184,200	63,100	48,880
Proceeds of property/equipment sales	3,700	19,042	22,600	27,100	1,261
Working capital (deficiency)	16,437	(2,346)	2,131	(16,950)	(399)
Total assets	740,454	624,195	469,954	306,463	245,342
Long-term operating bank debt	268,819	226,439	139,518	63,046	86,111
Shareholders' equity	328,992	262,932	203,766	120,734	88,427
Dividends paid	2,973	2,848	2,460	1,590	1,590
Per share	0.05	0.05	0.05	0.033	0.033

Share information	1999	1998	1997	1996	1995
Average number of common shares outstanding (thousands)	57,529	54,348	49,782	47,937	47,703
Market price					
High	\$ 26.00	\$ 17.00	\$ 17.75	\$ 9.00	\$ 5.33
Low	\$ 12.00	\$ 11.00	\$ 7.75	\$ 4.33	\$ 3.83

b) Annual Operating Information

(\$ thousands except per share amounts)	Year Ended December 31				
	1999	1998	1997	1996	1995
Reserves (proven and probable)					
Natural gas (Bcf)	750	788	637	476	448
Crude oil and liquids (MBbl)	8,880	11,630	13,440	10,662	6,585
Land holdings (000's acres)					
Gross	4,373	4,030	3,555	2,288	2,343
Net	2,834	2,443	2,032	1,464	1,469
Production					
Natural gas (MMcf/d)	220.0	203.5	148.6	127.1	135.0
Average natural gas price (\$/Mcf)	2.43	2.02	2.12	1.84	1.30
Crude oil and liquids (Bbl/d)	1,854	1,988	1,392	1,517	807
Average crude oil price (\$/Bbl)	24.27	19.22	26.36	27.91	20.66
Drilling activity					
Gas wells	92	111	81	78	101
Oil wells	9	24	28	17	7
Standing/service	3	8	28	—	—
Dry and abandoned	10	29	10	11	8
Total	114	172	147	106	116
Success rate (%)	91	83	93	90	93
Number of employees					
Office	70	63	53	47	48
Field	53	65	46	36	58
Total	123	128	99	83	106

⁽¹⁾All per share amounts are calculated using average number of shares outstanding, except dividends paid per share which are based upon actual shares outstanding at time of dividend declaration.

c) Quarterly Financial Information

The following information is presented with respect to each of the last eight fiscal quarters.

(\$ thousands except per share amounts)	1999				1998			
	Dec 31	Sept 30	June 30	March 31	Dec 31	Sept 30	June 30	March 31
Net revenue	44,417	45,263	42,527	41,884	45,999	34,402	33,259	30,993
Earnings	3,519	9,444	6,926	8,794	8,962	3,411	3,595	2,242
Per share	0.06	0.16	0.13	0.15	0.17	0.06	0.07	0.04
Cash flow	25,124	27,078	25,153	28,475	29,192	20,029	19,514	19,422
Per share	0.42	0.48	0.44	0.50	0.53	0.37	0.36	0.36

DIVIDEND POLICY

Paramount has paid a cash dividend each of the last five fiscal years. Although there is no intention to change the policy of paying dividends, future payments will be dependant upon the financial requirements of the Company to reinvest earnings, the financial condition of the Company and other factors which the Board of Directors of the Company may consider appropriate. The following table summarizes the Company's dividend payment record.

	1999	1998	1997	1996	1995
Per share	\$ 0.050	\$ 0.050	\$ 0.050	\$ 0.033	\$ 0.033
Dividends paid (\$ thousands)	\$ 2,973	\$ 2,848	\$ 2,460	\$ 1,590	\$ 1,590

MANAGEMENT DISCUSSION AND ANALYSIS ("MD&A" - SEE PAGES 33 TO 43)

See the Company's Management's Discussion and Analysis relating to the audited financial statements for the fiscal years ended December 31, 1999 and 1998, which form part of this Annual Report.

MARKET FOR SECURITIES

The Common shares of Paramount Resources Ltd. are listed on The Toronto Stock Exchange under the trading symbol 'POU'.

ADDITIONAL INFORMATION

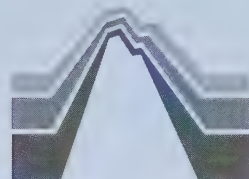
Additional information, including directors' and officers' remuneration, principal holders of Paramount Resources Ltd. securities, options to purchase securities, and interests of insiders in material transactions, where applicable, is contained in Paramount's Management Information and Proxy Circular dated March 30, 2000. Additional financial information is contained in the Company's comparative financial statements for the year ended December 31, 1999.

For additional copies of this Annual Report and the materials listed in the preceding paragraphs, please contact:

David J. Broshko, CA,
Chief Financial Officer

Paramount Resources Ltd.
Suite 4700 Bankers Hall West
888 Third Street S.W.
Calgary, Alberta
Canada T2P 5C5

Tel 403.290.3600
Fax 403.262.7994



Paramount
resources ltd.

SUPPLEMENT TO THE
 1999 ANNUAL REPORT

1999 analyst's handbook

This handbook has been prepared by Paramount Resources Ltd. to address the special information needs of the investment community and the sophisticated investor. The handbook provides detailed performance data and key ratios. For additional information please contact:

C.H. (Clay) Riddell, President

D.J. (David) Broshko, Chief Financial Officer

J.H.T. (Jim) Riddell, Corporate Operating Officer

S.L. (Sue) Riddell Rose, Corporate Operating Officer

corporate profile

Paramount Resources Ltd. is a Canadian energy company with over 90 percent of its revenue derived from natural gas sales. The Company explores for, develops, produces and markets natural gas, crude oil and natural gas liquids. Since its incorporation on February 14, 1978, the Company has become a major producer of shallow gas in northeastern Alberta. Paramount has an aggressive, focused exploration and development strategy, concentrated on acquiring land and establishing reserves throughout the Western Canadian Sedimentary Basin.

- 21 years old
- 123 employees (70 head office, 53 field)
- Listed on the Toronto Stock Exchange; symbol 'POU'
- Legal for Life
- Listed on TSE 200 Index
- 59.454 million shares outstanding
- Market Capitalization: \$1,011 million (December 31, 1999)

Year	Cash Flow	Per Share	Earnings	Per Share
1997	\$ 70.9 million	\$ 1.42	\$ 23.4 million	\$ 0.47
1998	\$ 88.1 million	\$ 1.62	\$ 18.2 million	\$ 0.34
1999	\$ 105.8 million	\$ 1.84	\$ 28.7 million	\$ 0.50

Average number of common shares outstanding for 1999 was 57,529,000.

Stock Split 3:1 Effective June 4, 1997. All 1997 per share data has been restated to give effect to the 3:1 share split.

unique traits

- High deliverability, long reserve life shallow gas in northeastern Alberta
- Over 90% of revenue derived from natural gas sales
- "Successful Efforts" accounting policy results in conservative net earnings

- High management ownership (54%)
- Successful full cycle exploration and development creates shareholder value
- Proven performance record through 21 years of commodity price cycles
- Exposure to high impact exploration plays in the Liard Basin and Cameron Hills in the N.W.T., and the San Joaquin Basin in California

consolidated earning & cash flow data

(\$ millions except per share amounts)

Years Ended December 31	1999	1998	Change
Revenue			
Natural gas	\$ 195.6	\$ 151.4	29%
Crude oil & liquid	16.0	14.1	13%
Royalties, net of ARTC	(37.5)	(20.9)	79%
Net revenue	174.1	144.6	20%
Expenses			
Operating	39.0	33.0	18%
Interest	15.0	12.7	18%
General and administrative	8.6	4.4	95%
Lease rentals	4.1	4.2	(2%)
Dry hole costs	10.4	11.7	(11%)
Geological and geophysical	2.4	5.1	(53%)
Site restoration	1.2	0.9	33%
DD & A	47.0	42.6	10%
Other (Income) net	(2.3)	(3.2)	(28%)
Current and capital taxes	1.6	2.1	(24%)
Deferred taxes	18.4	12.9	43%
Net earnings	\$ 28.7	\$ 18.2	58%
Net earnings per share	\$ 0.50	\$ 0.34	47%

cash flow reconciliation

Oil & gas revenue (net of royalties)	\$ 174.1	\$ 144.6	20%
Less expenses			
Operating	39.0	33.0	18%
Interest	15.0	12.7	18%
G & A	8.6	4.4	95%
Lease rentals	4.1	4.2	(2%)
Current & capital taxes	1.6	2.1	(24%)
Cash flow	\$ 105.8	\$ 88.1	20%
Cash flow per share	\$ 1.84	\$ 1.62	14%
Cash flow as a % of net revenue	61%	61%	—

major producing properties

The following table summarizes average production volumes from Paramount's major producing properties, for each of the five fiscal years.

Major Producing Properties

Natural gas (MMcf/d)	1999	1998	1997	1996	1995
Northeast Alberta – East Side					
Bohn Lake	4.8	—	—	—	—
Chard	3.5	4.2	3.6	4.8	5.5
Cold Lake	17.1	13.3	—	—	—
Corner	20.3	25.2	24.1	20.0	19.1
Kettle River	24.9	24.8	21.2	15.6	16.7
Leismer	3.5	3.1	3.7	1.5	1.9
Quigley	10.1	11.6	6.8	6.5	7.1
Thornbury	6.9	6.8	—	—	—
Winefred	7.1	6.5	—	—	—
Other	7.0	7.3	6.3	3.8	2.0
Northeast Alberta – West Side					
Legend	14.1	14.6	9.7	11.8	12.9
North Liege	4.6	6.3	8.3	11.0	13.7
South Liege	9.0	9.3	1.1	—	2.4
East Liege	5.7	—	—	—	—
Saleski	5.7	6.7	7.4	9.0	9.2
Teepee Creek	9.3	10.7	6.8	—	—
Central Alberta					
Kaybob	9.8	6.5	8.3	11.3	13.8
Kaybob North	24.5	13.2	7.3	3.3	—
Pine Creek	4.9	—	—	—	—
Zaremba	4.2	7.4	3.1	—	—
Other	4.2	—	—	—	—
Northwest Alberta					
Bistcho Lake	10.0	8.0	6.6	—	—
Pedigree	3.3	—	—	—	—
Other	0.7	—	—	—	—
Other	4.8	18.0	24.3	28.5	30.7
Total	220.0	203.5	148.6	127.1	135.0
Crude oil & liquids (Bbl/d)					
Alberta	839	1,021	711	1,120	807
Saskatchewan	852	790	616	332	—
Other	163	177	65	65	—
Total	1,854	1,988	1,392	1,517	807

undeveloped land

	Gross	Net
Alberta	1,950	1,388
British Columbia	191	105
Saskatchewan	199	39
Northwest Territories	494	221
Total undeveloped land	2,834	1,753
Net land	1999	1998
Proved	1,081	917
Undeveloped	1,753	1,516
Total net land	2,834	2,433
Appraised value of undeveloped land ⁽¹⁾	\$ 71.4	\$ 63.0

(1) Millions

Appraised value is an estimate of the fair market value of acreage based upon current analogous sales. Approximately 62% of the total net 1999 land inventory of 2.8 million acres is undeveloped.

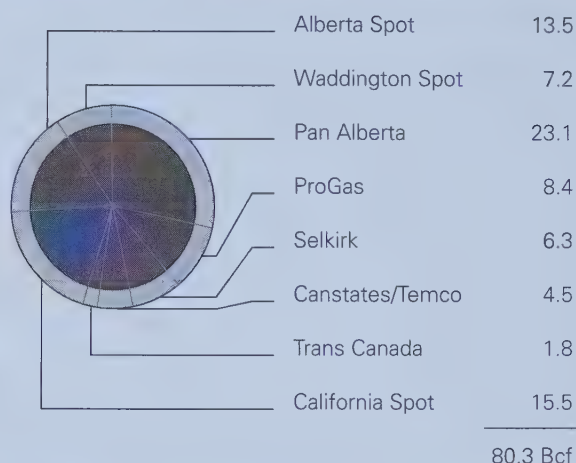
historical summary

	1999	1998	1997	1996	1995
Gas production (MMcf/d)	220.0	203.5	148.6	127.1	135.0
Crude oil & liquids production (Bbl/d)	1,854	1,988	1,392	1,517	807
Gas proven reserves (Bcf)	594.7	607.0	481.7	345.8	345.3
Crude oil & liquids proven reserves (MBbl)	6,267	7,895	8,386	5,574	3,095
Total proven and probable reserves (BCFeq)	838.6	904.5	771.2	583.0	514.1
Cash flow (\$MM)	\$ 105.8	\$ 88.1	\$ 70.9	\$ 63.1	\$ 35.3
Cash flow (\$/share)	\$ 1.84	\$ 1.62	\$ 1.42	\$ 1.32	\$ 0.74
Net earnings (\$MM)	\$ 28.7	\$ 18.2	\$ 23.4	\$ 25.5	\$ 5.6
Net earnings (\$/share)	\$ 0.50	\$ 0.34	\$ 0.47	\$ 0.53	\$ 0.12

gas sales & markets (MMcf/d)

	1999	1998
Pan Alberta	63	70
ProGas	23	24
Trans Canada	5	—
Canstates/Temco	12	12
Selkirk	17	16
California Spot	43	32
Waddington Spot	20	20
Alberta Spot	37	29
Total Sales	220	204
Aggregators	42%	46%
Direct sales	13%	14%
Spot Market	45%	40%

1999 natural gas contracts



capital expenditures (\$ millions)

	1999	1998
Drilling & seismic ⁽¹⁾	\$ 61.4	\$ 103.2
Land acquisitions	27.7	8.5
Property acquisitions	31.9	78.1
Facilities and equipment	36.5	42.2
Other	1.2	3.0
	158.7	235.0
Property dispositions	(1.9)	(19.0)
Total	\$ 156.8	\$ 216.0

(1) Net of tax effect of renounced exploration and development expenditure of \$14.3 million.

oil & gas sales and gross profit

This illustrates oil and gas sales since 1995 and converts the oil sales into gas equivalent (Mcfeq) on an industry standard basis of one barrel of crude oil/liquids equals 10 Mcf of natural gas.

Fiscal Year ⁽¹⁾	Oil & Gas Revenue		Gas Production		Oil & Liquids Production		Average Price		Gas Equivalent Production	
	(\$ 000s)	Trend	(MMcf)	Trend	(Bbl)	Trend	Gas (\$)	Oil (\$)	(MMcfeq)	Trend
1995	69,887	100	49,275	100	294,650	100	1.30	20.66	52,221	100
1996	100,644	144	46,392	94	553,605	188	1.84	27.91	51,924	99
1997	128,493	184	54,239	110	508,080	172	2.12	26.36	59,320	114
1998	165,527	237	74,278	151	725,620	246	2.03	19.22	81,578	156
1999	211,658	303	80,300	163	676,710	230	2.43	24.27	87,067	167

(1) Trend with base year 1995, with nominal value of 100

operating cash netbacks

Fiscal Year ⁽¹⁾	Royalties (net ARTC)			Operating Cost			Operating Cash Netback			
	(\$ 000s)	(\$/Mcfeq)	Trend	(\$ 000s)	(\$/Mcfeq)	Trend	(\$ 000s)	(\$/Mcfeq)	% of Revenue	Trend
1995	7,280	0.14	100	14,624	0.28	100	47,983	0.92	69.0	100
1996	7,763	0.15	107	16,196	0.31	111	76,685	1.48	76.2	110
1997	17,540	0.30	214	22,213	0.37	132	89,930	1.52	70.0	101
1998	20,874	0.26	186	33,005	0.40	143	110,077	1.35	67.1	97
1999	37,567	0.43	307	39,030	0.45	161	135,061	1.55	63.8	92

Operating Cash Netback = Oil & Gas Revenue – Royalty – Operating Cost

(1) Trend with base year 1995, with nominal value of 100

revenue/expenses/cash flow netback/net earnings

The table calculates revenue, expenses and net earnings converted into dollars per thousand cubic feet gas equivalents (1 Barrel equals 10 Mcf).

	1999	1998	1997	1996	1995
Annual Production (MMcfeq)	87,067	81,578	59,320	51,924	52,221
Revenue	\$ 2.43	\$ 2.03	\$ 2.20	\$ 1.94	\$ 1.34
Net Royalties	0.43	0.26	0.30	0.15	0.14
Operating costs	0.45	0.40	0.37	0.31	0.28
Cash netback	1.55	1.37	1.53	1.48	0.92
General and administrative	0.10	0.05	0.16	0.09	0.06
Interest on long-term debt	0.17	0.16	0.11	0.12	0.14
Lease rentals and other taxes	0.07	0.08	0.06	0.05	0.04
Cash flow netback	1.21	1.08	1.20	1.22	0.68
Depletion and depreciation	0.54	0.58	0.56	0.46	0.48
Gain on sale of properties	(0.02)	(0.04)	(0.21)	(0.07)	–
Dry hole costs	0.12	0.15	0.12	0.05	0.04
Geological and geophysical	0.03	0.06	0.03	0.07	0.06
Earning before income taxes	0.54	0.33	0.70	0.71	0.10
Deferred income taxes (recovery)	0.21	0.11	0.31	0.22	(0.01)
Net earnings	\$ 0.33	\$ 0.22	\$ 0.39	\$ 0.49	\$ 0.11
Net earnings trend ⁽¹⁾	300	200	355	445	100

(1) Trend with base year 1995, with nominal value of 100.

balance sheet information

As at December 31 (\$ millions)	1999	1998	Change
Assets			
Current assets	\$ 68.4	\$ 60.0	14%
Property & equipment (net)	672.1	561.6	20%
Other	—	2.6	(100%)
	\$ 740.5	\$ 624.2	19%
Liabilities			
Current liabilities	\$ 52.0	\$ 62.4	(17%)
Long-term debt	268.8	226.5	19%
Deferred revenue/other	8.7	8.8	(1%)
Deferred taxes	82.0	63.6	29%
Shareholders' equity	329.0	262.9	25%
	\$ 740.5	\$ 624.2	19%

net appraised asset value per common share

As at December 31, 1999 (\$ millions except per share amount)			
Discount rate	10%	15%	20%
Present value of net oil and gas reserves ^(1,2)	\$ 812.4	\$ 679.7	\$ 585.8
Appraised value of undeveloped acreage	71.4	71.4	71.4
Subtotal	883.8	751.1	657.2
Working capital	16.4	16.4	16.4
Operating long-term debt	(268.8)	(268.8)	(268.8)
Net appraised asset value	\$ 631.4	\$ 498.7	\$ 404.8
Net appraised asset value per common share ⁽³⁾	\$ 10.62	\$ 8.39	\$ 6.81

(1) Includes benefit of ARTC with no allowance for income tax

(2) Based upon Escalating Price Assumptions

(3) Based upon outstanding common shares 59,453,600 at December 31, 1999

capital structure

The following table outlines Paramount's capital structure since 1995.

(\$ thousands)	1999	1998	1997	1996	1995
Long-term debt	268,819	226,439	139,518	63,046	86,111
Deferred income tax	82,008	63,620	57,098	43,799	30,941
Deferred revenue and other	8,697	8,841	9,039	9,552	8,501
Common share equity	199,320	158,970	115,166	53,063	40,986
Retained earnings	129,672	103,962	88,600	67,671	47,441
	688,516	561,832	409,421	237,131	213,890

net debt

At December 31 (\$ thousands)	1999	1998
Current assets	\$ 68,375	\$ 60,017
Less current liabilities	51,938	62,363
Working capital (deficiency)	16,437	(2,346)
Long-term operating bank loans	268,819	226,439
Net debt	\$ 252,382	\$ 228,785

estimated future pre-tax cash flow

	Reserves Before Royalty		Present Value of Estimated Pre-Tax Cash Flow Discounted at:		
	Gas (Bcf)	Oil/Liquids (MBbl)	10%	15%	20%
Proven	595	6,264	676.3	577.4	505.4
Probable	155	2,616	136.1	102.3	80.4
Total	750	8,880	812.4	679.7	585.8

The discounted net present values of the estimated pre-tax cash flow expected during the economic life of all reserves are based on estimates using escalating price assumptions at rates of 10%, 15% and 20% per annum compounded annually. They are calculated prior to the consideration of income taxes but include ARTC, and are not to be construed as representing the fair market value of properties. The fair market value of the properties and such net present values will depend upon the subjective considerations inherent to each property.

key ratios

The following key ratio \$ to "fundamental analysis" have been calculated to accompany the Cash Flow Reconciliation.

- Cash Flow per Share
- Share Price to Cash Flow Multiple
- Debt to Cash Flow Ratio
- Debt to Equity Ratio
- Earnings Per Share
- Dividend Payout
- Rate of Return on Shareholders' Equity

Per share amounts for 1999 utilize the weighted average number of common shares outstanding of 57,529,000.

Cash Flow

Paramount calculates its cash flow;

- net of all lease rentals of both producing and non-producing properties
- net of all general and administrative costs, none of which are capitalized
- net of all marketing costs which are currently expensed
- net of all interest expenses, none of which are capitalized

Net Earnings

Paramount further calculates its net earnings;

- net of dry hole costs
- net of geological and geophysical costs

cash flow reconciliation

	December 31				
(\$ millions)	1999	1998	1997	1996	1995
Gross revenue	211.7	165.5	130.5	101.0	70.4
Net Royalties	37.6	20.9	17.4	7.8	7.3
Net revenue ⁽¹⁾	174.1	144.6	112.9	93.2	63.1
Less					
Operating costs	39.0	33.0	22.2	16.2	14.6
G&A	8.6	4.5	9.4	5.0	3.6
Lease rentals	4.1	4.2	2.5	1.9	1.9
Interest expense	15.0	12.7	6.7	6.4	7.2
Large Corporation Tax and other	1.6	2.1	1.2	0.6	0.5
Cash flow	105.8	88.1	70.9	63.1	35.3
Cash flow as a % of revenue	61	61	63	68	56

(1) Revenue net of royalties and ARTC

cash flow and cash flow/share

Fiscal Year	Cash Flow (\$ 000s)	Trend ⁽¹⁾	Year End Shares (000s)	Cash Flow per Share (\$)	Trend ⁽¹⁾
1995	35,313	100	47,703	0.74	100
1996	63,107	179	49,203	1.32	178
1997	70,911	201	53,954	1.42	192
1998	88,157	250	56,954	1.62	219
1999	105,830	300	59,454	1.84	249

(1) Trend with base year 1995, with a nominal value of 100

share price to cash flow multiple

Share Price as a Multiple of Cash Flow					
Fiscal Year	Share Low	Price (\$)	Cash Flow per Share (\$)	Low	High
1995	3.83	5.33	0.74	5.2x	7.2x
1996	4.33	9.00	1.32	3.3x	6.8x
1997	7.75	17.75	1.42	5.5x	12.5x
1998	11.00	17.00	1.62	6.8x	10.5x
1999	12.00	26.00	1.84	6.5x	14.1x

net debt to cash flow ratio

Fiscal Year	Net Debt (\$ 000s)	Cash Flow (\$ 000s)	Debt/Cash Ratio	Flow Trend ⁽¹⁾
1995	86,510	35,313	2.5:1	100
1996	79,996	63,107	1.3:1	52
1997	137,387	70,911	1.9:1	76
1998	228,785	88,157	2.6:1	104
1999	252,382	105,830	2.4:1	96

(1) Trend with base year 1995 with a nominal value of 100

debt to equity ratio

Fiscal Year	Operating Debt (\$ 000s)	Shareholders' Equity (\$ 000s)	Debt/Equity Ratio	Trend ⁽¹⁾
1995	86,111	88,427	0.97:1	100
1996	63,046	120,734	0.52:1	54
1997	139,518	203,766	0.68:1	70
1998	226,439	262,932	0.86:1	89
1999	268,819	328,992	0.82:1	85

(1) Trend with base year 1995 with a nominal value of 100

earnings per share

Paramount's earnings are net of dry hole costs, geological/geophysical costs, and all lease rentals.

Fiscal Year	Year End Earnings (000s)	Trend ⁽¹⁾	Shares (000s)	Earnings Per Share (\$)	Trend ⁽¹⁾
1995	5,622	100	47,703	0.12	100
1996	25,462	453	49,203	0.53	442
1997	23,389	416	53,954	0.47	392
1998	18,210	324	56,954	0.34	283
1999	28,683	510	59,454	0.50	417

(1) Trend with base year 1995 with a nominal value of 100

dividend payout

Paramount is one of the few oil and gas companies its size which declares a dividend. With the exception of 1987, a dividend has been paid every year since 1985.

Fiscal Year	Dividend per Share (\$)	Net Earnings per Share (\$)	Payout %
1995	0.033	0.12	27.5
1996	0.033	0.53	6.2
1997	0.050	0.47	10.6
1998	0.050	0.34	14.7
1999	0.050	0.50	10.0

rate of return on shareholder's equity

Paramount has earned a weighted average after-tax rate of return of 11.5% as computed on a book basis, based upon the weighted average shareholders' equity invested over the past five years.

(\$ thousands)	1999	1998	1997	1996	1995
Net earnings	28,683	18,210	23,389	25,462	5,622
Weighted average Shareholders' equity	295,962	233,300	162,250	104,600	86,400
After-tax rate of return (%)	9.7	7.8	14.4	24.3	6.5

company forecast 2000

Production / Pricing

Gas	260 MMcf/d @ \$ 2.95
Oil/Liquids	2,500 Bbl/d @ \$ 23.00
Cash flow (\$MM)	\$ 175
Cash flow per share	\$ 2.94
Capital budget (\$MM)	\$ 175

common share data

Shares of Paramount Resources Ltd. trade on The Toronto Stock Exchange under the symbol 'POU'. On January 12, 1998 Paramount was added to the TSE 300 Composite Index (Subgroup 3.2 Oil and Gas Producers) and the TSE 200 Index, effective January 16, 1998.

At December 31	1999	1998
Outstanding shares (000s)	59,454	56,954
Public float ⁽¹⁾ – shares (000s)	27,051	25,893
– % of total shares	46%	46%
Trading volume (000s)	12,014	9,900
Trading volume as % of public float	44%	38%
Trading value (000s)	\$ 227,226	\$ 142,266
Trading range		
High	\$ 26.00	\$ 17.00
Low	\$ 12.00	\$ 11.00
Close	\$ 17.00	\$ 15.00
Weighted average trading price	\$ 18.91	\$ 14.37
Market capitalization at year end (\$ millions)	\$ 1,010.7	\$ 854.3

(1) Public float is all outstanding shares less shares owned/controlled by officers/directors

directors and officers

C.H. (Clay) Riddell

Director, Chairman & President

D.J. (David) Broshko

Chief Financial Officer

J.H.T. (Jim) Riddell

Corporate Operating Officer

S.L. (Sue) Riddell Rose

Corporate Operating Officer

C.E. (Chuck) Morin

Corporate Secretary

L.A. (Laurel) Friesen

Assistant Corporate Secretary

J.F. (Jim) Jungé

Director

D.M. (David) Knott

Director

W.B. (Wally) MacInnes

Director

G.B. (Barry) Padley

Director

V.S.A. (Vi) Riddell

Director

J.B. (John) Roy

Director

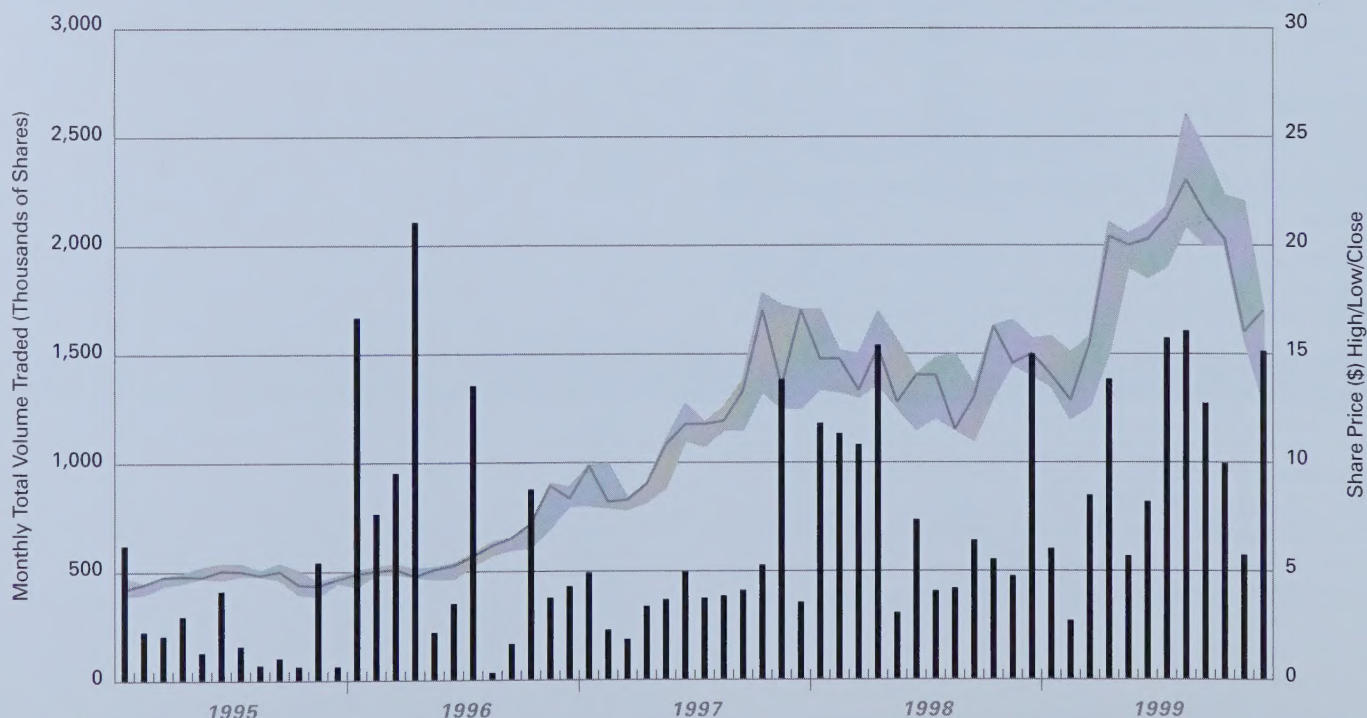
A.S. (Alistair) Thomson

Director

B.M. (Bernie) Wylie

Director

five year share price and trading volume



shareholder information

OFFICERS

C. H. Riddell
President

D. J. Broshko
Chief Financial Officer

S. L. Riddell Rose
Corporate Operating Officer

J. H. T. Riddell
Corporate Operating Officer

C. E. Morin
Corporate Secretary

L. A. Friesen
Assistant Corporate Secretary

HEAD OFFICE

4700 Bankers Hall West
888 3rd Street S.W.
Calgary, Alberta
Canada T2P 5C5
Telephone: (403) 290-3600
Facsimile: (403) 262-7994

ANNUAL MEETING

Shareholders are cordially invited to attend the Annual Meeting to be held June 8, 2000, at 3:00 p.m. at the Bankers Hall Auditorium Lower Level A
315 Eighth Avenue S.W.
Calgary, Alberta.

DIRECTORS

C. H. Riddell⁽³⁾
Chairman of the Board
President
Paramount Resources Ltd.

J. F. Jungé
Chairman of the Board
The Pitcairn Properties Inc.
Jenkintown, Pennsylvania

D. M. Knott
General Partner
Knott Partners, L.P.
Syosset, New York

W. B. MacInnes, Q.C.⁽¹⁾⁽²⁾
Barrister & Solicitor
Counsel, Ballem MacInnes
Calgary, Alberta

G. B. Padley⁽¹⁾
Business Executive
Calgary, Alberta

V. S. A. Riddell
Business Executive
Calgary, Alberta

J. B. Roy⁽¹⁾⁽²⁾⁽³⁾
Vice President & Director
Investment Banking
Jennings Capital Inc.
Calgary, Alberta

A. S. Thomson
President
Touche, Thomson & Yeoman
Investment Consultants Ltd.
Calgary, Alberta

B. M. Wylie⁽²⁾⁽³⁾
Business Executive
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Environmental Committee
(3) Member of Compensation Committee

CONSULTING ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

BANKERS

Bank of Montreal
Main Branch
Calgary, Alberta

Royal Bank of Canada
Main Branch
Calgary, Alberta

Canadian Imperial Bank of Commerce
Main Branch
Calgary, Alberta

SOLICITORS

Ballem MacInnes
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Montreal Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
(‘POU’)

Paramount Resources Ltd.
4700 Bankers Hall West
888 3rd Street S.W.
Calgary, Alberta
Canada T2P 5C5

Tel 403.290.3600

Fax 403.262.7994